SMALL HYDROELECTRIC DEVELOPMENT STUDY
NORTHWEST TERRITORIES

A Feasibility Study

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NORTHWEST TERRITORIES

A Feasibility Study

Prepared for:

Northern Canada Power Commission

Prepared by:

Hydrowest Consultants Inc.

With a contribution from:

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The purpose of the program is to promote the adoption of alternative energy supplies and to encourage energy conservation in remote communities.

The program is aimed specifically at power generation and space heating on the community scale. Its goal is to reduce dependence on oil and broaden awareness of more appropriate (and often locally available) renewable fuels, conservation methods and other practical alternatives.

During the course of this study there were a number of meetings and discussions between the consultant and a Study Management Committee (SMC). The SMC was instituted to monitor the progress of the study, and as it turned out, the SMC not only monitored, but was of assistance shaping the direction of the study. In addition, the members were of assistance to the Consultant in providing data and information on a number of matters. Appreciation is expressed to the members of the SMC who were:

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METRIC-IMPERIAL CONVERSION TABLE

TO CONVERT FROM IMPERIAL TO METRIC			TO CONVERT FROM METRIC TO IMPERIAL
Multiply by	Metric	Imperial	Multiply by
2,54	Centimetre (cm)	Inch (in.)	0,394
0,305	Metre (m)	Foot (ft.)	3,281
1,609	Kilometre (km)	Mile (mi.)	0,621
0,092	Square metre (m2)	Square foot (ft2)	10,763
0,836	Square metre (m^2)	Square yard (yd^2)	1,196
2,590	Square kilometre (km2)	Square mile (mi2)	0,386
0,404	Hectare (ha)	Acre (ac.)	2,471
0,028	Cubic metre (m3)	Cubic foot (ft^3)	35,315
0,765	Cubic metre (m3)	Cubic yard (yd3)	1,308
1,233	Cubic decametre (dam^3)	Acre-foot (ac-ft.)	0,811
4,546	Litre (L)	Gallon (gal.)	0,220
0,159	Cubic metre (m^3)	Barrel-oil (bbl.)	6,29
0,454	Kilogram (kg)	Av. pound (lb.)	2,205
0,907	Tonne (t)	Ton (2000 lb.)	1,102
3,6	Megajoule (MJ)	Kilowatt.hour (kWh)	0,278
0,076	Litre per second (l/s)	Gallon per minute (gal./min.)	13,198
0,028	Cubic metre per second (m^3/s)	Cubic foot per second (cfs)	35,315

GLOSSARY

ACTIVE LAYER	The layer of the soil that usually freezes in the winter and thaws in summer, found immediately above permanently frozen ground.
ALBEDO	The fraction of the total sunlight falling on a surface that is reflected back. Snow reflects about 75% and dense forests about 5% of solar radiation. Water reflects between 4% and 40%, depending on its clarity, and absorbs the other 96% to 60%.
ALLUVIUM (ALLUVIAL)	More or less stratified deposits of sand, silt, gravel, and other coarse debris moved by streams from higher to lower ground. It is the general term for all sediment deposited on land by streams.
BANK	Ascending slope bordering a river or lake. Left and right banks are determined by facing downstream.
BANKFULL	The flow stage of a river in which the stream completely fills its channel from the riverbed to the top of the river banks.
BASEFLOW	Streamflow that is composed entirely of groundwater and other inflows, when there is no direct runoff from precipitation or snowmelt.
BEDLOAD	Material dragged along in contact with the bed of a stream.
BEDROCK	Solid rock of the earth's crust exposed at the surface of the earth, or covered with unconsolidated materials such as silts, sands, and gravels.
BOG	Peat-covered area with a high water table and a surface carpet of mosses, chiefly sphagnum. The bog is virtually isolated from mineral soil waters; hence the surface bog waters and peat are strongly acid, and the upper peat layers are extremely deficient in mineral nutrients. Bogs may have trees or may be treeless and may have shrubby plants.

BOREAL FOREST	Northern forests that consist primarily of coniferous trees such as spruce, fir, and pine, but also include deciduous trees such as aspen, birches, poplars, and willows.
CLIMATE	The sum total of the meteorological elements that characterize the average and extreme condition of the atmosphere over a long period of time at any one place or region of the earth's surface. These elements include temperature, moisture, precipitation, wind, pressure, and evaporation.
DAM	A natural or man-made obstruction in a river valley, such as a lava dam or beaver dam or different types of engineering structures for water storage or hydroelectric power production.
DENSITY OF WATER	The density of water is greatest at 4°C. It becomes less dense as it warms and more important, as it cools to freezing at 0°C. At that temperature, it changes to ice, which floats because its density is less than that of water. Therefore only very shallow lakes and ponds (no more than 2 to 3 m) freeze to the bottom.
DISCHARGE	In the case of a river, the volume of flow per unit time across a given cross-section, usually expressed in cubic metres per second (m^3/s).
DRAINAGE BASIN	The total area that contributes runoff water to a stream. The amount of water reaching the stream depends on the size of the basin, precipitation, and losses due to deep percolation, evaporation, and absorption by the soil and vegetation, among other factors; also known as WATERSHED.
DRAWDOWN	The change in the water level of a natural body of water, well, or reservoir as a result of withdrawing water.
ECOSYSTEM	A natural system of all plants and animals and their environment, and the way they adjust to that environment and each other (derived from the words ecological system).

ENVIRONMENT	The sum of all external forces, conditions, and influences that affect the existence and development of plants and animals. Air, light, moisture, temperature, wind, soil, and other organisms are called environmental factors (also see ECOSYSTEM).
EROSION	The wearing away and removal of soils, rocks, and landforms by the physical and chemical action of moving water, ice, air, and gravity. Simply, the detachment and movement of soil or rock by water, wind, ice or gravity.
EVAPOTRANSPIRATION	The combined loss of water from a given area by evaporation from the soil surface and by transpiration from plants growing on the land.
FLOATING ICE	Any form of ice found floating in water, or temporarilly stranded or grounded.
FLOOD	Any relatively high level or flow of water that overtops natural or artificial banks in a lake or any reach of a river.
FLOODPLAIN	The flat land bordering a stream, built up of sediments from overflow of the stream and subject to inundation when the stream is at flood stage.
FLOW DURATION CURVE	A graph showing the percentage of time that a given flow in a river is equalled or exceeded. If the ratio of the flow to the average flow is used a dimensionless curve is obtained. The flow could be for any time period, e.g., daily, weekly, monthly.
FRAZIL ICE	A mush of ice spikelets and water resembling slush, formed by freezing in turbulent flowing water. Frazil ice formed in turbulent waters at rapids and waterfalls during prolonged cold spells is granular or spiky.
GAUGE	An instrument for measuring and recording the stage of a river or amount of rainfall, termed river gauge or rain gauge, respectively. It may have an automatic recording device.

GEOMORPHIC PROCESSES	All those physical and chemical processes that change the earth's landforms and landscapes.
GEOMORPHOLOGY	The study and scientific interpretation of topographic features (landforms).
GROUNDWATER	Subsurface water occurring below the water table, that is, in the saturated zone in which all soil pores are filled with water. The water above the water table is referred to as soil moisture.
HEADWATERS	The upper reaches of a drainage system, or the waters upstream of an engineering structure.
HYDROGRAPH	A graph showing the flow (discharge), stage (level), velocity, or other characteristics of flowing water at a given location over time. This provides a picture of river flow variations from day to day and year to year.
HYDROLOGIC CYCLE	Also known as the water cycle. This is the never-ending circulation of water and water vapour over the entire earth, from the atmosphere to the surface of the earth and back to the atmosphere, by precipitation, runoff, percolation, storage, evaporation, and transpiration.
HYDROLOGY	A scientific and engineering discipline dealing with the occurrence of water on and under the earth's surface, its physical and chemical properties, as well as its distribution and movement.
ICE JAM	An accumulation of broken river ice or sea ice caught in a narrow channel.
ICE LENS	A discontinuous layer of ground ice tapering at its extremities. Ice lenses in soil occur roughly parallel to each other, generally coincident with the direction of heat loss, and commonly in repeated layers.
ISOHYD	A line of equal RUNOFF.

ISOHYET	A line of equal precipitation.
LOCAL INFLOW	The summation of all discharges from inflowing streams along a river reach.
MEANS ANNUAL DISCHARGE	Essentially the daily flow of water averaged over the length of time that records are available (the period of record). It is calculated by taking the arithmetic mean of the "annual mean discharge" (that is, the annual mean of daily discharges for an entire single year) for all years over the period of record.
MUSKEG	A type of bog, often with a mat of vegetation and scattered black spruce or tamarack (larch) trees.
PERMAFROST	Perennially frozen ground occurring wherever the temperature remains below 0°C for several succeeding years. It may be continuous, discontinuous (scattered), or localized.
PINGOS	Small dome-shaped hills composed of ice, 10-100 m in diameter, and raised by frost action as much as 30 m above the surrounding terrain.
POLYGONS	Patterns of cracks in permafrost areas, generally produced by alternate freezing and thawing of the surface soil.
PRECAMBRIAN SHIELD	Also known as the Canadian Shield or simply Shield. The huge tract of land in subarctic Canada that extends from the Atlantic to the Arctic Ocean and is composed of the oldest rocks of the earth's crust. Its low relief surface shows the effect of intense continental glacier erosion.
REACH	A particular section or length of river considered as a unit for study, design, mathematical modelling, or descriptive purposes.
RESERVOIR	Artificial lake created behind a dam for storing water or producing hydroelectric power.
RIVERBED	The lower and normally submerged part of a river channel, excluding the banks of a stream.

RIVER CHANNEL	The space above the riverbed and between the banks of a stream.
ROUTING	The technique of calculating the hydrography of a downstream location from the hydrograph of an upstream location in that river system, taking local inflows and the effects of intervening channel, valley, and lake storage into account. Routing changes the shape of the hydrograph, usually by flattening out the peaks and valleys.
RUNOFF	The portion of the total precipitation on an area that flows away in surface streams.
SEDGES	Grasslike plants that typically have solid triangular-shaped stems, as opposed to grasses whose stems are cylindrical or flattened in shape. Sedges inhabit marshy places, the banks of streams, and the shores of ponds and lakes.
SEDIMENT	All soil and rock particles resulting from the weathering of rock and removed by water, air, ice, or gravity. When the water velocity decreases in a river, this suspended material settles out but may be successively picked up again and re-deposited.
SILTING	The deposition of waterborne sediments in stream channels, lakes, reservoirs,or on floodplains, usually resulting from a decrease in the velocity of the water.
SNOWMELT	Water resulting from melting snow.
SPRING BREAKUP	The destruction of the winter ice cover by the combined forces of solar radiation and high runoff from snowmelt. The sun initially weakens the ice cover. The water flowing under the ice then fractures and uplifts it, as the volume of flow increases, and moves the broken ice downstream.
SPRING FLOOD	High streamflow that overtops the river banks when snowmelt increases the runoff sharply each spring.

SOLIFLUCTION	The slow downhill flow of surface deposits saturated with water released by thawing. Mostly limited in usage to such movements in permafrost or periglacial regions.
SPECIFIC YIELD	The amount of runoff from a drainage basin expressed as litres per second per square kilometre (l/s/km2).
STREAM	A body of running water moving under the influence of gravity to lower levels in a narrow, clearly defined natural channel. Streams are referred to as brooks, creeks, streams, and rivers.
STREAMFLOW	The flow of surface water between well-defined stream or river banks. The volume of flow is calculated by multiplying the measured velocity of water by the cross-sectional area of the river at that point, and is expressed in cubic metres per second (m^3/s).
SUSPENDED SOLIDS (SEDIMENT)	The solid material suspended in a stream. It may be carried a great distance or for a considerable period of time by current and turbulence.
TOPOGRAPHY	The general configuration of a surface, including its relief. It may be a land or water-bottom surface.
TRANSPIRATION	The process by which water exhales or escapes from the pores of living plant tissues and enters the atmosphere. Transpiration is the water discharge of vegetation.
TUNDRA	Undulating and treeless arctic plain with perennially frozen, patterned ground. The impermeable near-surface permafrost table creates marshy conditions on the surface in summer. The summers are short, but the days long. Vegetation consists mainly of mosses, lichens, sedges, herbs, and dwarf species of alder, birch, and willow.
WATER BUDGET	The hydrologic balance of a river basin consisting of a systematic summary of the inflow, storage, losses, and outflow of water for the entire watershed.

WATER TABLE	The level below which the ground is completely saturated with water (also see GROUNDWATER).
WEIR	A barricade across a stream over which water flows. It may be constructed to raise the water level or to measure streamflow.

SUMMARY - VOLUME 1

This Study was undertaken to identify and test the feasibility of small hydroelectric plants, or alternative energy sources, in replacing or reducing the use of oil in six communities in the Northwest Territories. The six community, which are located between [illegible]°N and 68°N Latitude and 68°W and 122°W longitude, Figure 1 [illegible]r Lake, Coppermine, Fort Simpson-Trout Lake, Frobisher Bay, R[illegible] and Rankin Inlet, and they presently obtain electricity from [illegible] generators and heat by the combustion of oil or wood.

As a first step towards solving this problem, load forecasts were prepared for a 40 year period. The forecast was based on

- population and its projected growth;
- consumption of electrical energy per capita;
- consumption of oil for heating;
- temperature variations in the coldest month.

The basic forecast was adjusted to produce five scenarios, which took into account conservation measures and an improved lifestyle. The five scenarios are:

- extension of the present electrical demand, with and without energy conservation;
- extension of the existing electrical load plus heating requirements, with and without energy conservation;
- extension of the existing electrical demand increased for improved lifestyle and heating requirements and decreased by energy conservation. This is the medium combined load.

The hydroelectric sites were selected to meet a number of conditions, namely

- they should be operational all year round, and storage should be available if necessary;
- their capacity should be sufficient to meet both the projected normal electric load and the heating load, but the smallest acceptable capability would be that of meeting the projected normal electric load;

- the site should not normally be more than 25 km from the load centre to reduce transmission line costs. For Fort Simpson, the transmission distance of the most suitable site was about 120 km from the load centre;

- because of climatic conditions the water conveyance system should be as short as possible.

Site specific hydrologic data was not available for all of the sites, and the analysis was therefore done on a regional basis. The regional analysis was used to produce average river flows and flood flows.

The study was divided into three phases, each phase using somewhat better information than the preceeding one. In the first phase, head differences were obtained from topographic maps to a scale of 1:250 000 with 30.5 m (100 ft) contour intervals. In the second and third phases of the study, the available heads were based on field measurements.

In the first two phases of the study, the cost effectiveness of a hydroelectric scheme was obtained by comparing the effective cost of energy from the hydro plant with the weighted cost of energy from the existing diesel generating and oil combustion systems. This comparison gave a cost index for the project. The effective cost of hydro energy was based on the annual cost of the hydro plant and the actual energy consumed, as given by the load forecast. The annual cost took into account amortization, depreciation, replacement, and operation and maintenance costs. The weighted cost of the existing systems reflected the cost of diesel energy and the cost of heating. The costs which were used in these calculations were all present values in 1984 dollars.

In the last phase of the study, cost streams for the amortization and operation of a hydro-diesel system and an all diesel system were present valued and compared. The resulting analysis, which was done by a computer, gave benefit-cost ratios, internal rates of return, cost of energy, optimum plant size, optimum time of commissioning the hydro plant, and the time period to recover the initial investment on the hydro plant.

The only practical alternative energy source which is compatible with the load, climate in the communities and the state of technological development, is wind energy. This alternative was investigated briefly for all of the communities with the objective of meeting the normal electric load only. However, wind generators must be used in a hybrid system to provide acceptable system reliability. For heating, alternative energy sources are gas and wood.

The main results of the investigations which were carried out for each community are as follows.

BAKER LAKE

Two schemes satisfied the criteria outlined above, but only the scheme on the Thelon river advanced to the second phase of the study. The scheme consisted of an 11 m high overflow, rockfill dam across the Thelon river near Tupik Lake and an underground powerhouse in the left bank of the river. Plant flows varying from 143 m3/s to 198 m3/s were investigated, i.e., plant capacities varying from 5,6 MW to 10,1 MW, respectively were analysed. The energy from the plants varied from 46,7 GWh p.a. to 84,3 GWh p.a., respectively, and could therefore meet both the normal electric load and the heating load.

The hydro plant most likely to compete with the existing system was the 5,6 MW alternative which was estimated to cost $56,7 millions with a cost margin of ± 20%. At 80% of the capital cost and using a discount rate of 6% p.a., the effective cost of energy was found to be 14,0 ¢/kWh. When compared to the weighted cost of energy from the existing system at 11,6 ¢/kWh, it was clear that the hydro project was not economically viable.

The main reasons contributing to the high hydro energy costs were:

- the small load and hence the under-utilisation of the potential of the site;
- high civil works costs caused by the relatively large size of the Thelon river;
- the need to create head by constructing a dam;

Wind energy appears to show promise as an alternative energy source for Baker Lake. The cost of wind energy, based on preliminary wind data, was estimated at 16,0 ¢/kWh at 6% discount rate. However, before any final statement can be made on the suitability of wind generators, basic site specific wind data should be collected over a period of at least one year.

COPPERMINE

This hydro project for this community at Bloody Falls in the Coppermine river, was the only one which was studied in some detail. One site on the Kendall river and another at Escape rapids, Coppermine river, were inferior to the Bloody Falls site. The project consists of an interception trough in the river just upstream of the falls, an intake, 5,4 m diameter power and tailrace tunnels and a semi-underground powerhouse in the left bank of the river. The optimum plant size uses 46 m^3/s under a head of 5,0 m to produce 1888 kW of firm power, i.e., the plant uses less than the estimated minimum flow in the river without the use of a dam.

This plant, which is estimated to cost $16,1 millions, would be used primarily to meet the normal electric load. Excess energy could be used for heating. However, since there is only one hydro unit, the existing diesel plant was assumed to be retained to maintain the reliability of the system, but run only nominally. The cost of this hydro-diesel system was compared to an all diesel system at a decision discount rate of 8% p.a.

For the all diesel system, energy is produced at 37,8 ¢/kWh, while energy from the hydro-diesel system is obtainable at 33,6 ¢/kWh, when excess energy is used for heating. When the excess energy is not utilised, the cost is 43,4 ¢/kWh. In the case of full use of the hydro energy, the pay back period is 20 years with a benefit cost ratio of 1,17; for no use of the surplus energy the pay back period is extended to 40 years. For a 20% increase in the capital cost, the benefit cost ratio is reduced to 0,93% at the decision discount rate.

Wind as an alternative energy source was not found to be attractive, because of the low wind regime. At 8% p.a. discount rate the cost of wind energy is 43,4 ¢/kWh.

The development of the Bloody Falls site is contingent upon proper environmental studies being undertaken, especially with respect to arctic char. This fish is an important source of protein to the community, and any development which would adversely affect the fish would be unacceptable. As the project is presently designed, it is believed that there is little adverse environmental impact on the project.

FORT SIMPSON - TROUT LAKE

The only suitable hydro site was found on the Trout river. The proposed development consisted of headworks at the outlet of Trout Lake, an upstream power plant about 35 km downstream of the lake, and a second power plant near Whittaker Falls. The project design requires spring and summer flows to Trout Lake to be stored for release during the winter.

Both powerhouses have a maximum plant flow of 39,2 m^3/s. The upstream plant has a capacity of 8,5 MW and the net head is 26,6 m, while the downstream plant has an installed capacity of 5,5 MW under a smaller net head of 17,9 m. The energy from both plants can satisfy both the normal electric load and the heating load for 30 years.

Energy would be transmitted to Fort Simpson, 120 km away from the downstream plant, and to Trout Lake 68 km away from the upstream plant. The estimated capital cost of the project was $58,8 million and the effective cost of energy was found to be 8,7 ¢/kWh. This cost is more than the weighted cost of the existing systems, namely 7,9 ¢/kWh, both at 6%

p.a. discount rate. Hence the Trout river developments are not competitive with the existing system. It must be noted here that the main reason for the project not attaining economic viability is due to the long transmission lines, and is not due to any intrinsic deficiency of the hydroelectric sites.

Wind as an alternative electric energy source was not found to be possible because of the low wind speeds in the area.

FROBISHER BAY

This study primarily reviewed and revised the findings of earlier work done on potential hydro sites on the Sylvia Grinnell river. The proposed project consisted of a control structure at the outlet of Sylvia Grinnell lake which would be used to store spring and summer flows. These flows were then to be released to a downstream power plant about 10 km from Frobisher Bay. Since there was no natural head, a 56 m dam was proposed along with a spillway and powerhouse with an installed capacity of 7,5 MW.

The estimated cost of this development, which could provide energy to meet only the normal electric load for about 40 years, was $94 million. The effective cost of energy was found to be 20,6 ¢/kWh at 6% p.a. discount rate, and it compared unfavourably with the cost of diesel energy at 19,5 ¢/kWh.

A serious disadvantage of this project is the construction of a 56 m high dam, on a river which has a relatively small runoff. It would therefore appear that the existing systems for heating and producing electricity provide, at this time, the optimum solution to the energy needs of Frobisher Bay.

RAE LAKES

Three hydro schemes were investigated for this community, one at the outlet of Faber Lake, a second at the outlet of Lac Ste Croix and the last between Rae Lake and Taka Lake. The best scheme was the Rae Lake/Lac Ste Croix project which required a small overflow dam and intake between the two lake systems, a short canal and a powerhouse at Lac Ste Croix. The turbines used 9,2 m^3/s under a net head of 5,4 m, and the power plant had an installed capacity of 250 kW. The energy which was produced could meet total energy demand, but not the peak power demand.

The estimated capital cost of the selected scheme was $4,4 million and the effective cost of energy was found to be 17,6 ¢/kWh at 6% p.a. discount rate. When compared with the weighted cost of energy from the existing systems, namely 10,8 ¢/kWh, it became clear that the project was not economically viable.

Wind as an alternative energy source was found to be more expensive than the energy from the diesel plants. Wind energy was estimated to cost 62,7 ¢/kWh at 6% p.a. discount rate, while the cost of diesel energy was 27,2 ¢/kWh.

RANKIN INLET

It was found that any hydro development in the Rankin Inlet area could only provide enough energy to meet an electric load. The project which was investigated was on the Diana river. The intake was located near the outlet of Diana Lake and water was conveyed by a canal; part of the canal system utilised three lakes. The gross head which was obtained was 10,8 m and the plant flow was taken to be 27,9 m^3/s.

This plant flow was based on the assumption that water from Gibson Lake could be transferred to Diana Lake; the Gibson catchment contribution forms nearly 70% of the plant flow.

Subsequent field surveys were able to indicate that the possibility of transferring water from Gibson Lake to Diana Lake was quite low. This was due to the relatively high terrain between the two catchments. Consequently, the project became technically not feasible.

Wind as an alternative energy source was investigated, and the estimated cost of wind energy is 17,0 ¢/kWh compared to 23,1 ¢/kWh for diesel generation. This estimate is based on the wind regime at Chesterfield Inlet, and it is therefore necessary to obtain site specific data. This data should be collected over a period of one year.

CONCLUSIONS

It must therefore be concluded that the development of small hydroelectric plants to displace oil is not viable for Baker Lake, Fort Simpson-Trout Lake, Frobisher Bay, Rae Lakes and Rankin Inlet. At Coppermine, the Bloody Falls scheme may be marginally economical, but a full feasibility and environmental study would be required to confirm this. Wind as an alternative energy source is worth further investigation at Baker Lake and Rankin Inlet.

SUMMARY - VOLUME 2

This report describes the pre-feasibility level assessment of possible hydroelectric development near Coppermine, NWT. This study is part of a larger program that considered small hydro projects at six communities in the Northwest Territories, as described in the main study report volume.

This study was undertaken on behalf of the Northern Canada Power Commission (NCPC) with the objective of locating a hydroelecrtric site that could be developed to supply energy to the small Inuit community at Coppermine. The hamlet of Coppermine is located on the northern coastline of mainland Canada at the mouth of the Coppermine river. The construction of a hydroelectric plant in the area, which is north of the arctic circle, would therefore make this plant the most northerly hydroelectric development in Canada.

There are about 890 people in Coppermine most of whom are Inuit. The lifestyle of the community is largely traditional although this is changing. The community is located in a zone of continuous permafrost and above the tree line. Average monthly temperatures vary from -30,1° C, in January, to 9,7°C in July. Temperatures are below freezing for 8 months of the year. Because of the geographic location of the hamlet, daylight hours vary from zero to 24 hours.

Presently, the community is supplied with electricity generated by a diesel generating plant which has an installed capacity of 1575 kW. In the fiscal year 1983/84, 2,66 GWh of electricity were generated and the peak load was 620 kW.

As might be expected, heating is required all year round, although the summer heating requirement is small. Space heating is provided by the direct combustion of home heating oil.

The initial objective of the study was to develop a hydroelectric plant which would meet both the normal electric load and the space heating load. However, as the study developed, economic assessments dictated that only the projected normal electric load should be met, and that excess energy would be available for heating. The projected normal electric load at the end of the ecomonic life of the hydro plant was estimated to be about 8,0 GWh p.a.

Based on previous work which was done, three hydroelectric sites were examined. One was located on the Kendall river near Dismal Lakes, and two on the Coppermine River. These two latter sites were Escape Rapids and Bloody Falls. The Bloody Falls site was found to be the best for the following reasons:

- it is located closest to the community, and would require a transmission line of about 15 km;
- there is a natural head of about 6m;
- the Coppermine river does not freeze to the bottom during winter.

Examination of the site evolved from a desk study using 1:250 000 scale maps to one based on field measurement of the gross head at the falls. Based on the information obtained during the field visit, a new topographic map to a scale of 1: 2 500 was prepared using existing air photographs. Geotechnical evaluation of the site was based on a ground reconnaissance and on photo-geological interpretation of the area.

The evaluation of available flows at the site was based on a regional estimate of runoff in the Northwest Territories. There was also limited information on flows at Coppermine, since Water Survey of Canada had erected a gauging station just upstream of the falls in 1983.

The first layout of the project consisted of a dam and intake upstream of Bloody Falls, a tunnel and the powerhouse at the downstream end of the falls. This configuration was later changed to remove the environmental problems which would be created by the dam. These problems centered principally around the fish population in the river. It was necessary to ensure that the migratory pattern of the arctic char and other fishes, which provides about 32% of the diet of the Inuit, was not disturbed.

The present layout consists of an intercepting trough which is excavated in the river bed and thus allows flows to be diverted to a semi-underground powerhouse via an intake and a 5,4 m diameter concrete lined tunnel. Water is returned to the river by a tailrace tunnel of the same diameter as the headrace tunnel. Four schemes with capacities varying from 922 kW to 2800 kW were investigated. The selected scheme, based on the economic analysis, is one with rated output of 1888 kW. However, a nominal 2 MW plant can be installed. There is only one generator driven by a Kaplan turbine.

The selected plant utilises a flow of 46 m^3/s under a net hed of 5,06 m. Since the minimum flow in the Coppermine Riiver at Bloody Falls is estimated to be 58 m^3/s, the average energy production is the same as the firm energy output. The rated energy output from the plant is estimated to be about 15,8 GWh p.a. The estimated capital cost of the project is $16,066 million, in 1984 dollars, excluding the cost of a feasibility and environmental studies. It is estimated that these studies would cost an additional one million dollars.

Construction of the project is estimated to take 34 months. Although the critical construction item is the manufacture and delivery of the generating equipment, the construction of the diversion trough must be done in two seasons since there would be no cofferdam across the river. The contruction of the trough is done during the periods of low flow.

The evaluation of the project was made by comparing system capital and operating costs with and without the hydro plant. The analysis was made with real discount rates of 6%, 8% and 10%.

The analysis considered that the hydro energy in excess of the normal electric load demand would be utilised for space heating. The value of the energy used for heating was taken as 6,4 ¢/kWh, which is 90% of the equivalent electrical cost of home heating oil. It was shown that at the decision discount rate of 8% p.a. the hydro plant would yield a benefit cost rates of 1,17. When the cost of the project was increased by 20%, it was found that this reduced to 0,93 and the internal rate of return was 7,9%. Based on the estimated cost of the project, the cost of energy at the decision discount rate was estimated as follows:

Diesel generating system	37,8¢/kWh
Hydro-diesel system	33,6¢/kWh
Hydro generation costs	31,7¢/kWh

The payback period was found to be 20 years and the optimum year of installation is 1992.

If the excess hydro energy is not utilised, it was found that the cost of energy from the hydro-diesel system was 43,4¢/kWh at the decision discount rate. Also, the payback period would be extended to 40 years.

The environmental impact of the project would be small, since there is no structure aross the river. However further studies, particularly relating to fish life in the river, would be required.

The possibility of using wind as an alternative energy source was also examined briefly. But it was not found to be a viable proposition.

A feasibility study would be required to confirm the technical and economic viability of the Bloody Falls project. Environmental studies relating to the fish life in the river are a prior requirement of any feasibility study.

ÉTUDE D'AMÉNAGEMENTS HYDRO-ÉLECTRIQUES À PETITE ÉCHELLE DANS LES TERRITOIRES DU NORD-OUEST

y compris un examen détaillé de l'aménagement de Coppermine

Résumé

PARTIE I

Cette étude a été entreprise afin de déterminer et de démontrer la faisabilité du recours à de petites centrales hydro-électriques ou à d'autres modes de production d'énergie pour remplacer ou réduire la consommation de mazout dans six agglomérations des Territoires du Nord-Ouest. Les six collectivités, situées entre 62 et 68° de latitude nord et 68 et 122° de longitude ouest, sont Baker Lake, Coppermine, Fort Simpson-Trout Lake, Frobisher Bay, Rae Lakes et Rankin Inlet. Toutes tirent leur électricité de génératrices au diesel et se chauffent soit au bois soit au mazout.

Pour ébaucher une solution, des prévisions de charge ont été faites pour une période de 40 ans. Ces prévisions se fondent sur:

- la population et sa croissance projetée;
- la consommation d'électricité par habitant;
- la consommation de mazout de chauffage;
- les variations de température durant le mois le plus froid.

Les prévisions de base ont été rajustées afin d'obtenir cinq scénarios préconisant des mesures d'économies d'énergie et une amélioration du mode de vie. Voici les cinq scénarios:

- maintien de la demande actuelle d'électricité, avec et sans économies d'énergie;

- maintien de la charge actuelle, plus les besoins de chauffage, avec et sans économies d'énergie;

- maintien de la demande actuelle d'électricité, accrue pour répondre à un mode de vie amélioré et aux besoins de chauffage et réduite grâce à des économies d'énergie. Il s'agit là de la charge moyenne combinée.

Les sites d'aménagement hydro-électrique ont été choisis en fonction de nombreux critères, notamment:

- ils doivent pouvoir produire à longueur d'année et offrir la possibilité, au besoin, de stockage;

- leur puissance doit être suffisamment élevée pour satisfaire tant à la demande projetée d'électricité qu'à la demande de chauffage. La puissance minimale acceptable répondrait au moins à la demande normale d'électricité;

- le site ne devrait pas habituellement se trouver à plus de 25 km de la région de desserte afin de réduire le coût du transport. Dans le cas de Fort Simpson, la distance entre le site le plus convenable et cette région est de 120 km;

- étant donné le climat, il faudrait réduire au minimum la longueur des conduites d'eau.

Nous ne disposions pas de données hydrologiques propres à chaque site. L'analyse s'est donc effectuée dans un contexte régional. Elle a servi à obtenir des débits moyens des eaux de la rivière et des crues.

L'étude comporte trois phases, chacune reposant sur de l'information un peu plus précise que la précédente. La première phase a servi à établir les écarts de chute à partir de cartes topographiques au 1/250 000^e dont les courbes de niveau sont équidistantes de 30,5 m (100 pi). Durant les deuxième et troisième phases, les hauteurs de chute utilisées se fondent sur des études du terrain.

Dans les deux premières phases, la rentabilité d'un aménagement hydro-électrique est établie en comparant le coût pondéré de l'énergie provenant de centrales existantes alimentées au diesel et au mazout. Cette comparaison a donné un indice de coût du projet. Le coût réel de l'énergie hydro-électrique repose sur le coût annuel de la centrale et sur la consommation réelle d'énergie, telle qu'établie par les prévisions de charge. Le coût annuel tient compte de l'amortissement, de la dépréciation, du remplacement et des frais d'exploitation et d'entretien. Le coût pondéré des installations actuelles témoigne du coût du combustible diesel et du coût de chauffage. Tous les coûts utilisés dans ces calculs sont des valeurs actualisées en dollars de 1984.

Durant la dernière phase, les courbes de coûts pour l'amortissement et l'exploitation d'une centrale hydraulique au diesel et d'une centrale uniquement au diesel ont été actualisées et comparées. L'analyse qui en est résultée, effectuée par ordinateur, donnait les rapports avantages-coûts, les taux internes de rendement, le coût de l'énergie, la taille optimale de la centrale, le moment idéal pour passer la commande de l'usine et la période de récupération de l'investissement initial.

La seule autre source d'énergie utilisable, étant donné les contraintes de charge, de climat et de technologie, est l'énergie éolienne. Cette source possible a été brièvement étudiée pour chacune des agglomérations, dans l'optique de ne répondre qu'à la demande normale d'électricité. Il faut toutefois inclure des génératrices éoliennes dans une installation hybride si l'on veut assurer l'approvisionnement. Pour chauffer, le gaz et le bois sont préférables.

Voici les faits saillants des études qui ont porté sur chaque agglomération.

Baker Lake

Deux scénarios répondaient aux critères énoncés plus haut. Seul le scénario de la rivière Thelon a réussi à passer à la deuxième phase de l'étude. Il s'agit d'un trop-plein de 11 m de hauteur, d'un barrage d'enrochement franchissant la rivière près de Tupik Lake et d'une centrale souterraine creusée dans la rive gauche de la rivière. Des débits à l'usine variant entre 143 et 198 m^3/s ont été examinés, soit des puissances de 5,6 à 10,1 MW respectivement. L'électricité produite par ces machines varie entre 46,7 et 84,3 GWh par année respectivement, ce qui veut dire que les besoins tant de charge normale que de chauffage seraient satisfaits.

La centrale hydro-électrique la plus indiquée pour rivaliser avec l'installation actuelle est l'usine de 5,6 MW dont le coût est évalué à 56,7 millions de dollars, à 20% près. Au coût le plus bas (80 % du coût estimatif) en capital, actualisé selon un taux de 6% par année, le prix réel de revient de l'électricité serait de 14 ¢/kWh. Il est clair que le projet de centrale hydraulique n'est pas rentable si l'on tient compte du coût pondéré de l'électricité obtenue de l'installation existante, soit 11,6 ¢/kWh.

Les principaux facteurs contribuant à ce coût élevé sont:

- la faible charge et, partant, la sous-utilisation du potentiel hydro-électrique;
- le coût élevé des travaux de génie civil qu'entraîne la largeur de la rivière Thelon;
- la nécessité de construire un barrage pour réaliser une hauteur de chute.

L'énergie éolienne semble prometteuse en tant qu'énergie de remplacement à Baker Lake. D'après des données préliminaires sur le régime des vents, son coût s'établit à 16 ¢/kWh, à un taux d'actualisation de 6%. Cependant, avant de se prononcer sur l'utilisation de génératrices éoliennes, il faudrait réunir des données fondamentales sur le régime des vents au site pendant au moins un an.

Coppermine

Ce projet de centrale hydro-électrique pour desservir la collectivité à partir de Bloody Falls, sur la rivière Coppermine, est le seul que nous ayons étudié en détail. Un des autres sites se trouvait sur la rivière Kendall, et un autre à Escape Rapids, sur la rivière Coppermine; les deux étaient moins avantageux que celui de Bloody Falls. Le projet consiste en un canal de collecte creusé dans la rivière juste en amont des chutes, un ouvrage de prise d'eau, des galeries d'alimentation et de fuite de 5,4 m de diamètre et une centrale semi-souterraine creusée en bordure gauche de la rivière. La centrale optimale utiliserait 46 m^3/s d'eau sous la chute de 5 m afin de produire 1 888 kW d'énergie ferme, c'est-à-dire qu'elle absorberait moins que le débit minimal estimatif de la rivière, sans barrage.

La faisabilité d'une telle centrale, dont le coût estimatif est de 16,1 millions de dollars, repose sur l'hypothèse que la centrale servirait surtout à répondre à la demande normale de charge, l'excédent étant réservé pour le chauffage. Cependant, comme il n'y a qu'une unité hydraulique, la centrale existante au diesel serait maintenue afin d'assurer la fiabilité de l'approvisionnement. Toutefois, elle ne fonctionnerait que nominalement. Le coût de cette installation hybride a été comparé à une installation brûlant uniquement du diesel, à un taux d'actualisation retenu de 8% par année.

Le prix de revient de l'énergie produite par la centrale entièrement alimentée au diesel est de 37,8 ¢/kWh, contre 30,5 ¢/kWh pour l'installation hybride lorsque l'énergie excédentaire est absorbée par le chauffage. Si cette énergie excédentaire n'est pas utilisée, le prix de revient passe alors à 37,6 ¢/kWh. Lorsque toute l'hydro-électricité est utilisée, la période de récupération est de 15 ans, et le coefficient de rentabilité, de 1,41; dans le cas contraire, il faut 33 ans pour recouvrer l'investissement. Si le coût en capital augmente de 20 %, le coefficient de rentabilité tombe à 1,17 %, selon le taux d'actualisation retenu.

En tant qu'énergie de remplacement, le vent n'est pas attrayant en raison du faible régime qui domine dans cette région. À un taux d'actualisation de 8 %, le prix de revient de l'énergie éolienne s'établit à 43,4 ¢/kWh.

Comme condition préalable à l'aménagement de Bloody Falls, il faudrait exécuter les études environnementales appropriées, surtout en ce qui concerne l'omble chevalier. Ce poisson représente une source importante de protéines dans l'alimentation de la population. Tout aménagement susceptible de nuire à ce poisson serait donc inacceptable. Tel que conçu actuellement, le projet aurait peu de conséquences du genre.

Fort Simpson - Trout Lake

Le seul site convenable d'aménagement hydro-électrique se trouve sur la rivière Trout. Cet aménagement comprendrait des travaux de tête au point de déversement de Trout Lake, une usine amont qui se trouverait à peu près à 35 km en aval du lac et une seconde usine près des chutes Whittaker. Tel que le projet est conçu, il faudrait stocker les eaux du printemps et de l'été pour les utiliser durant l'hiver.

Les deux usines ont un débit maximal de 39,2 m^3/s. La centrale en amont a une capacité de 8,5 MW et une hauteur nette de chute de 26,6 m, tandis que l'autre a une capacité installée de 5,5 MW sous une hauteur de chute plus faible, soit de 17,9 m. L'énergie produite par ces deux centrales peut répondre à la demande normale de charge comme à la demande de chauffage pendant 30 ans.

L'énergie serait transportée jusqu'à Fort Simpson, à 120 km de la centrale aval, et jusqu'à Trout Lake, à 68 km de la centrale amont. Le projet absorberait approximativement 58,8 millions de dollars en immobilisations, et le prix de revient de l'électricité serait de 8,7 ¢/kWh. Elle coûte donc plus cher à produire que l'électricité des installations existantes, qui revient à 7,9 ¢/kWh, les deux coûts étant actualisés à un taux de 6% par année. Les aménagements sur la rivière Trout ne pourraient donc pas rivaliser avec les méthodes actuelles d'approvisionnement. Il faudrait noter ici que la principale raison pour laquelle ce projet n'est pas rentable est la longueur excessive des lignes de transport, et ne vient pas d'une lacune intrinsèque des sites.

L'énergie éolienne comme énergie de remplacement ne convient pas en raison de la faible vitesse des vents dans cette région.

Frobisher Bay

Cette étude a surtout été consacrée à un examen et à une revue des résultats de travaux effectués antérieurement concernant des sites éventuels d'aménagements hydro-électriques sur la rivière Sylvia Grinnell. Le projet comportait un ouvrage de régulation au point de déversement du lac Sylvia Grinnell qui pourrait servir à stocker les eaux du printemps et de l'été. Ces eaux seraient ensuite acheminées vers une centrale en aval, à environ 10 km de Frobisher Bay. Comme il n'existe pas de chute naturelle, il faudrait construire un barrage de 56 m, de même qu'un déservoir et une centrale dont la puissance installée serait de 7,5 MW.

Le coût estimatif de cet aménagement qui ne répondrait qu'à la demande normale de charge pendant 40 ans est de 94 millions de dollars. Actualisée selon un taux annuel de 6 %, l'électricité produite reviendrait en réalité à 20,6 ¢/kWh, ce qui se compare mal à l'énergie produite par moteur diesel dont le coût est de 19,5 ¢/kWh.

Un sérieux désavantage de ce projet est qu'il faudait construire un barrage de 56 m de hauteur sur une rivière dont les eaux s'écoulent relativement lentement. Il semblerait donc que le régime actuel de chauffage et de production d'électricité demeure pour l'instant la meilleure solution aux besoins énergétiques de Frobisher Bay.

Rae Lakes

Trois scénarios ont été envisagés pour cette agglomération, l'un au point de déversement du lac Faber, un autre au point de déversement du Lac Ste Croix et un troisième entre Rae Lake et Taka Lake. C'est ce dernier qui a été jugé le meilleur: il requiert la construction d'un petit barrage de trop-plein et d'un ouvrage de prise d'eau entre les deux lacs, un canal court et une centrale à Lac Ste Croix. Les turbines sont alimentées en un débit de 9,2 m^3/s sous une hauteur nette de chute de 5,4 m, et la centrale a une puissance installée de 250 kW. L'électricité produite pourrait répondre à tous les besoins, mais pas à la demande de pointe.

Les frais estimatifs d'immobilisations de ce projet sont de 4,4 millions de dollars, et le coût réel de l'énergie produite, à un taux d'actualisation annuel de 6 %, de 17,6 ¢/kWh. Si l'on compare ceci au coût pondéré de l'énergie actuellement produite, soit 10,8 ¢/kWh, il est évident que le projet n'est pas viable.

L'énergie éolienne serait encore plus chère. On évalue son prix de revient à 62,7 ¢/kWh, d'après un taux d'actualisation de 6 % par année, alors que celui de l'énergie produite par moteur diesel est de 27,2 ¢/kWh.

Rankin Inlet

Peu importe le projet à l'étude, le site aménagé ne suffirait qu'à satisfaire aux besoins de chauffage. Le projet étudié est situé sur la rivière Diana. L'ouvrage de prise d'eau se trouve près du débouché du lac Diana, d'où l'eau est acheminée par canal; une partie des canalisations emprunte trois lacs. La hauteur brute de chute obtenue est de 10,8 m, et le débit à l'usine de 27,9 m^3/s.

Ce débit suppose que l'eau du lac Gibson serait déversée dans le lac Diana; cet apport représenterait presque 70 % du débit.

Des études menées subséquemment sur le terrain ont réussi à faire ressortir la faible possibilité de détourner l'eau du lac Gibson vers le lac Diana, en raison d'un terrain relativement élevé entre les deux bassins. Techniquement, donc, le projet n'est pas réalisable.

L'utilisation du vent comme énergie de remplacement a été examinée. Son prix de revient estimatif est de 17 ¢/kWh, contre 23,1 ¢/kWh pour l'électricité produite par moteur diesel. Ces calculs estimatifs se fondent sur le régime des vents à Chesterfield Inlet. Obtenir des données propres au site s'impose donc. Ces données pourraient être recueillies durant une période d'un an.

Conclusion

Il faut donc conclure que l'aménagement de petites centrales hydro-électriques pour s'affranchir du pétrole ne serait pas rentable à Baker Lake, à Fort-Simpson-Trout Lake, à Frobisher Bay, à Rae Lakes et à Rankin Inlet. Cependant, on devrait entreprendre une étude de faisabilité complète du site

de Bloody Falls pour l'agglomération de Coppermine. Par ailleurs, le recours à l'énergie éolienne comme énergie de remplacement à Baker Lake et à Rankin Inlet mérite une étude plus poussée.

PARTIE II

Le présent rapport fait état de l'évaluation préalable à la faisabilité d'un aménagement hydro-électrique près de Coppermine, dans les Territoires du Nord-Ouest. Cette étude relève d'un programme plus étendu visant des projets d'aménagement hydro-électriques dans six agglomérations des Territoires du Nord-Ouest, tel que décrit dans le rapport d'étude principal.

L'étude a été commandée par la Commission d'énergie du Nord canadien qui cherche des sites que l'on pourrait aménager pour fournir de l'électricité à la petite collectivité inuit de Coppermine. Ce hameau est situé sur la côte nord de la masse continentale du Canada, à l'embouchure de la rivière Coppermine. Si une centrale hydro-électrique était construite dans cette région, qui se trouve à l'intérieur du cercle polaire, il s'agirait de l'aménagement hydro-électrique le plus septentrional du Canada.

Coppermine compte environ 800 habitants, la plupart Inuit. Le mode de vie y est en grande partie traditionnel, bien que cela change. L'agglomération est située dans une zone de pergélisol continu, au-dessus de la ligne des arbres. La température moyenne y varie, de -30,1 °C en janvier, à 9,7 °C en juillet. Le thermomètre se maintient donc sous le point de congélation pendant huit mois de l'année. De par sa situation géographique, ce hameau bénéficie de la lumière du jour de zéro à 24 heures.

Actuellement, la collectivité obtient son électricité d'une centrale au diesel dont la puissance installée est de 1 575 kW. Durant l'exercice 1983-1984, 2,66 GWh d'électricité ont été produits, et la charge de pointe a été de 620 kW.

Comme on pouvait s'y attendre, il faut chauffer à longueur d'année, même si les besoins, en été, sont faibles. Les locaux sont chauffés au mazout domestique.

L'objectif premier de cette étude était de trouver un concept de centrale hydro-électrique qui répondrait tant à la demande normale de charge qu'aux besoins de chauffage. Cependant, au fil de l'étude, il a été décidé de ne chercher à satisfaire qu'à la demande normale de charge, en réservant l'excédent pour le chauffage. La demande normale d'électricité qui est projetée à la fin de la vie économique de la centrale a été évaluée à environ 8 GWh par année.

À la lumière de travaux antérieurs, trois sites ont été examinés. L'un est situé sur la rivière Kendall, près des lacs Dismal, et les autres sur la rivière Coppermine, à Escape Rapids et à Bloody Falls. Ce dernier site a été retenu pour les raisons qui suivent:

- c'est l'endroit le plus proche de Coppermine, ce qui veut dire que la ligne de transport n'aurait que 15 km à peu près;
- la hauteur de chute, naturelle, y est d'environ 6 m;
- les eaux au fond de la rivière Coppermine ne gèlent pas l'hiver.

Cet examen du site a commencé par une étude de bureau au moyen de cartes au 1/250 000^e, suivie de la prise de mesures, sur place, de la hauteur brute des chutes. Grâce à ces nouvelles données, une carte topographique révisée a été dressée au 1/2 500^e au moyen de photos aériennes. L'évaluation géotechnique du site reposait sur une reconnaissance au sol et sur l'interprétation photogéologique de la région.

L'évaluation des débits d'eau s'est fondée sur une évaluation régionale des écoulements dans les Territoires du Nord-Ouest. Il existait aussi un peu d'information sur les débits à Coppermine, étant donné que la Water Survey of Canada a construit une station de mesure juste en amont des chutes en 1983.

La première ébauche de projet comprenait un barrage et un ouvrage de prise d'eau en amont de Bloody Falls, un tunnel et une centrale à l'extrémité aval des chutes. Cette architecture a été changée par la suite afin d'éliminer certains problèmes environnementaux causés par le barrage qui aurait nuit surtout aux poissons de la rivière. Il fallait s'assurer que les tracés migratoires de l'omble chevalier et d'autres espèces, qui représentent environ 32 % de l'apport alimentaire des Inuits, ne seraient pas perturbés.

L'agencement actuel comprend un canal de collecte creusé dans le lit de la rivière qui permet de détourner les eaux vers une centrale semi-souterraine au moyen d'un ouvrage de prise d'eau et d'un tunnel de 5,4 m de diamètre. L'eau est retournée à la rivière par un tunnel de fuite de même diamètre que le tunnel d'amenée. Quatre aménagements différents, de puissance variant entre 922 et 2 800 kW, ont été étudiés. L'option retenue, à la fin de l'analyse économique, est celle qui produirait une capacité nominale de 1 888 kW. Cependant, une centrale de puissance nominale de 2 MW peut être installée. Une seule génératrice y est prévue, actionnée par une turbine Kaplan.

La centrale choisie utiliserait un débit de 46 m^3/s sous une hauteur nette de chute de 5,06 m. Comme le débit minimal de la rivière Coppermine à Bloody Falls est évalué à 58 m^3/s, la production moyenne d'énergie est égale à la production d'énergie ferme. La production nominale d'énergie de l'usine est évaluée à environ 15,8 GWh par année. Le coût estimatif des immobilisations est de 16 066 millions de dollars 1984, exclusion faite du coût des études de faisabilité et de l'environnement. On estime à un million de dollars le coût supplémentaire de ces études.

La construction prendrait 34 mois. Même si le point critique de cette étape est la fabrication et la livraison du matériel de production, la construction du canal de détournement doit se faire en deux saisons étant donné qu'il n'y aurait pas de batardeau franchissant la rivière. La construction de ce canal doit se faire durant les périodes de faible écoulement des eaux.

Le projet a été évalué en comparant le coût d'immobilisation et d'exploitation de l'installation avec et sans centrale hydro-électrique. L'analyse reposait sur des taux réels d'actualisation de 6, de 8 et de 10 %.

Dans cette analyse, il était établi que l'énergie excédant la demande normale de charge servirait à chauffer les locaux. La valeur de l'énergie utilisée pour le chauffage a été établie à 6,4 ¢/kWh, ce qui revient à 90 % du coût de chauffage au mazout domestique. Il a été démontré qu'en utilisant un taux d'actualisation de 8 % par année, la centrale avait un coefficient de rentabilité de 1,40. Lorsque le coût monte de 20 %, le taux interne de rendement est de 9,4 % pour un taux d'actualisation, en termes réels, de 8 % par année. Le coût de l'énergie ainsi produite est évalué, selon le coût estimatif du projet, à:

Génératrice au diesel	37,8 ¢/kWh
Moteur diesel et turbine hydraulique	30,5 ¢/kWh
Coût de production hydro-électrique	25,7 ¢/kWh

La période de récupération est de 15 ans, et l'année optimale d'installation, 1992.

Si l'énergie hydro-électrique excédentaire n'est pas utilisée, le coût de l'électricité produite par un moteur diesel combiné à une turbine hydraulique passe à 37,3 ¢/kWh, au taux d'actualisation retenu. De plus, la période de récupération passe à 33 ans.

L'incidence environnementale du projet serait minime puisqu'aucune construction ne traverse la rivière. Cependant, il faudrait effectuer d'autres études, surtout en ce qui concerne le poisson de la rivière.

La possibilité d'avoir recours au vent comme énergie de remplacement a aussi fait l'objet d'un bref examen. Cependant, cette proposition ne semble pas viable.

La viabilité technique et économique du site de Bloody Falls, telle qu'établie dans cette étude, révèle qu'une étude de faisabilité s'impose. De plus, il faudrait mener au préalable des études environnementales concernant la vie du poisson dans la rivière.

Cette étude a été entreprise par Hydrowest Consultants Inc. pour le compte de la Commission d'énergie du Nord canadien avec le concours financier d'Énergie, Mines et Ressources Canada, dans le cadre de son Programme de démonstration dans les collectivités éloignées.

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VOLUME I -

SMALL HYDROELECTRIC DEVELOPMENT STUDY, N.W.T.

SECTION 1 - INTRODUCTION

1.1 PURPOSE AND AUTHORIZATION

1.1.1 Purpose

The purpose of this Study was to evaluate the technical and economic feasibilities and opportunities for the development of small scale hydroelectric generating stations, and other energy supply alternatives, at six specific locations in the Northwest Territories. The hydroelectric stations were to be designed to either replace or supplement existing diesel electric generation and, if possible, space heating oil at Baker Lake, Coppermine, Fort Simpson-Trout Lake, Frobisher Bay, Rae Lakes and Rankin Inlet.

This pre-feasibility study was funded by Energy Mines and Resources Canada under the Remote Community Demonstration Program and administered by the Northern Canada Power Commission. The study was authorized by the Northern Canada Power Commission on 12 March, 1984 on behalf of the Study Management Committee whose members are listed in the acknowledgement.

The six communities mentioned above were selected from a list of forty one analysed in previous studies, References 25 and 29, and were assumed to have reasonable prospects for development.

1.2 TERMS OF REFERENCE

The Terms of Reference of the Study are given below. After the completion of Task Ten, the remaining tasks were revised to relate specifically to the selected project.

TASK ONE

Undertake a full assessment of hydrological data to determine existing flow regimes, and any storage or diversions between river systems which may be required to ensure adequate minimum flows for electrical generation purposes. Without limiting the scope of this Task, NCPC have identified the following diversion and small hydro site potentials which should be considered in this study:

a) Frobisher Bay (potential hydro site at Sylvia Grinnel River)

b) Fort Simpson (potential hydro site at Trout River and Trout Lake)

c) Baker Lake (potential hydro site at Anigag River and diversion from Thelon River to Anigag River, potential hydro site at Kazan Falls)

d) Rankin Inlet (potential site at Diana River with consideration for upstream diversion from adjacent river basin)

e) Coppermine (potential site at Kendall River at Dismal Lakes)

f) Rae Lakes

TASK TWO

Provision of an electrical demand forecast including consideration of:

a) the expected electrical demand if all existing alternate oil fired and other space heating equipment were replaced by electricity;

b) the expected increase in electrical demand if a more abundant and economic electricity supply were available to improve the quality of life; and

c) the expected electrical demand as evaluated in items (a) and (b) above, but including the further assumption that full advantage is taken of energy conservation opportunities.

TASK THREE

Based on the energy demand forecast scenarios defined in Task Two, an appropriate range of plant capacities will be selected for evaluation.

TASK FOUR

Desk studies - (based on existing information, including for example, air photo interpretation) - will be carried out to determine to the fullest extent possible if economic opportunities exist for the development of small hydro including identification of other energy supply alternatives which could supply - in whole or in part - the energy supply requirements of the communities considered in this study. Also to be included in this Task is the definition of environmental concerns raised in each community relative to possible hydro development and power transmission in their areas. Environmental concerns raised in the communities will be provided by the co-ordinator.

TASK FIVE

Provision of Milestone Report for consideration of Management Committee.

TASK SIX

Based on the results of Task Five, the Management Committee will give approval for specific hydro electric site reconnaissance surveys. These surveys will be carried out to confirm or determine head range developable, key water levels, major structure dimensions, local physical features including foundations, and construction materials availability.

TASK SEVEN

Based on existing information and on site surveys, community input will be gathered so as to confirm preliminary environmental and socio-economic impact assessment of potential hydro sites. In this respect, it is noted that assessment of environmental impact must include consideration of all aspects which are important to each community. For example, NCPC have noted that consideration must be given to the relationship between the Arctic Char Fishery and potential hydroelectric development on the Sylvia Grinnel River.

Task Seven (A)

Provision of Milestone Report for consideration by the Management Committee.

TASK EIGHT

Develop preliminary generating stations layouts and related cost estimates (including transmission costs) for a range of installed plant capacities capable of meeting existing and anticipated energy demands in each community.

TASK NINE

The hydroelectric alternatives will be evaluated in a comparative analysis in terms of capital, operating and life cycle costs considering alternative energy costs, overall systems reliability, potential interconnection of electrical transmission systems (e.g., Baker Lake and Rankin Inlet), the cost of continued diesel generation, and potential economic and environmental impacts.

TASK TEN

Provision of Milestone Report for consideration of Management Committee.

REVISED TASK ELEVEN

Based on the findings of the second Milestone Report and the assessment of those findings by the Management Committee, the Bloody Falls site, Coppermine River, is to redesigned as a run-of-the-river hydroelectric plant with no dam placed across the river. The detailed layout and design of the project is to be taken to a prefeasibility level and a range of plant capacities is to be investigated. The smallest plant capacity must be capable of satisfying the normal electric load as given by the load forecasts of Task 3. The design will include:

- layout;
- type and size of mechanical and electrical equipment;
- estimate of all civil engineering quantities;

An economic evaluation of the selected project, in terms of benefit cost ratios and/or internal rate of return, is to assume that all excess hydro energy is to be used for heating. Economic sensitivity tests varying the price of oil, construction cost and interest rates (6%, 8% and 10%) are to be carried out. The performance of the hydro plant and the existing diesel plants operated as a system is to be analysed, and the reliability of the hydro-diesel system is to be indicated.

REVISED TASK TWELVE

A final report is to be prepared covering:

a) the merits of the small hydro plants which were investigated as a means of meeting the energy needs of the communities;

b) recommendations and guidelines for the implementation of the Bloody Falls hydroelectric project, if proven to be economically viable;

c) the use of wind as an alternative energy source for each community.

A separate report, in summary form and suitably written for the use of the communities, is also to be prepared.

1.3 REPORT ORGANIZATION

The report on the overall study program has been prepared in three volumes.

- Summary Report for use at the Community Level
- Final Report that covers the overall study program including the identification and evaluation of sites at each community.
- Appendix Report "Coppermine Development". This is the pre-feasibility level report that describes the possible hydro-development at Bloody Falls, and includes the evaluation of power and non-power aspects.

1.4 STUDY AREAS

The six communities are located between latitudes 62°N and 68°N, and longitude 68°W and 122°W, Figure 1.1 The northern most community, Coppermine, lies north of the Arctic Circle, 66°-30°N. Fort Simpson and Rae Lakes lie within the Mackenzie drainage basin. Baker Lake and Rankin Inlet lie in Western Hudson Bay drainage basin and Frobisher Bay on Baffin Island is the most easterly of the communities.

With the exception of Rae Lakes and Fort Simpson-Trout Lake, the remaining communities are located north of the tree line and in a zone of continuous permafrost, Figure 1.2. Beyond the tree line the vegetation in these areas is of the tundra type. Rae Lakes and Fort Simpson are located in the zone of widespread permafrost and there are sufficient trees to provide for cooking and space heating needs in traditional households.

Based on population, the communities are quite small varying from less than 210 at Rae Lakes to 2 630 at Frobisher Bay. The population is composed largely of Inuits, Dene, Metis and Euro-Canadians, in that order. The economic base of the communities rests on traditional activities such as hunting, fishing, trapping, carving and other crafts, and employment in the civil service or local service sector. Large scale development plans for the area are not known and the present economic base does not suggest rapid economic growth.

SECTION 2 - METHODOLOGY

The study approach involved a progressive screening of potential hydroelectric sites as the quality of the data base increased.

2.1 STUDY PROGRAM

The Study program which was followed was divided into three phases.

- Phase 1 consisted of desk studies to define the available hydro generation potential and the electrical demands of the communities, followed by preliminary evaluation of costs and the economic viability of the projects.
- Phase 2 was dependent on the selection of the more favorable sites indicated in the Phase 1 work. Limited field investigations were carried out for these selected sites and the projects were re-evaluated.
- Phase 3 was again dependent on the selection of the best site for further refinement and re-evaluation.

Originally, the project was scheduled to be completed in September/October 1984, but a major break from June to August was necessary to allow for ice break-up and suitable conditions for performing the field work. In addition, a revision of the terms of reference after the Phase 2 work was completed necessitated an extension of the completion date of the Study to January 1985.

2.2 PHASE ONE

In this first phase of the study, the following criteria and assumptions were adopted:

Hydroelectric Site Selection

- the hydroelectric potential of each site should be greater than the existing electrical load and, if possible, the combined load consisting of the electrical equivalent of the heating oil and the existing electrical load;

- the cost of energy from the hydroelectric plants should be less than the cost electricity from the existing diesel generators when the plant can only serve the normal electric load;
- the net present value of the diesel fuel plus the space heating oil, when the plant can also serve the heat load, discounted over the economic life of the hydroelectric projects at specified discount rates was to delineate the maximum investment for the potential hydroelectric sites;
- the potential hydro sites were to be located as close as possible to the communities to reduce capital expenditure on transmission lines. This distance was taken as 25 km;
- storage was to be provided at each hydro site, if necessary, to maintain flows in the winter when the energy demand was at its highest.
- the drainage basin was to be as large as possible to obtain the required flow. Diversion of adjoining drainage basins was resorted to, if necessary;
- the layout of the projects was to be oriented towards obtaining the maximum possible natural head, and the existence or connection of existing lakes was given priority in laying out any canal system;
- because of the climatic conditions, any canal, pipeline or tunnel forming a part of the water conveyance system was to be as short as possible. A minimum depth was established for canals to prevent complete freeze-up;
- the dams were to be of the free overflow, rockfill type not involving the use of concrete. In addition, the dams were to be located at or near rapids where the foundation would be rock;
- the location of the intake should be at a lake or small reservoir because of the need for winter ice cover. Tailrace discharges were to be beneath the ice cover.

Load Forecast

Preliminary load forecasts were produced for all six communities for both the normal electric load and space heating markets.

The following methodology was used for all of the sites to prepare a ten year forecast to the year 1994:

- forecast electrical growth using population forecasts and 1982/83 consumption/capita factors plus capital projects forecast by the Government of the Northwest Territories (GNWT).
- forecast space heating growth using population and household characteristics plus capital projects forecast by the GNWT.
- combine the electrical and space heating loads and increase it by a factor 18% to allow for distribution and transmission losses. This gave the average generation required at the bus bar of the hydro plant.
- obtain the plant capacity based on the heating requirements for an average January multiplied by a factor of 1,6 plus the normal electrical load. This factor allows for the variation in average January temperatures, and was obtained by multiplying the ratio of the highest number of degree-days in one day in January to the average for one day in January, and the ratio of the highest number of degree days in January to the average for January.

Power and Energy

In the majority of the schemes which were examined the average energy demands for the normal electric load and the heating load of each community could be met. In other cases, the potential of the schemes could satisfy only the normal electric load. However, because of the extreme variation of the temperature during the year, and during any particular winter month, the resulting heating load required additional energy and plant capacity; the effect of this was to incur additional cost for extra capacity with no change in the average energy output. In estimating the energy capabilities, a utilisation factor of 0,95 was used to allow for the inability to use water at all times.

Project Costs

The cost estimates of the schemes were prepared by applying unit costs to specific quantities. These costs were compiled with the aim of reflecting construction conditions in the Northwest Territories. Some of the quantities have been based on the available topographic maps, and therefore have an inherent error. The costs which have been supplied must be considered as order of magnitude values with an error of about ± 20%, excluding allowances to correct any environmental requirements. Also, for calculating the interest during construction, a three year construction period was adopted, and costs resulting from the mitigation of environmental effects were omitted.

Economic Comparisons

The cost effectiveness of a scheme was obtained by comparing the effective cost of energy from the hydroelectric schemes to the equivalent oil values for the supply of electricity plus heat or electricity alone, depending on whether the hydroelectric schemes were capable of supplying both electricity and heat loads or could meet the electrical load only.

The equivalent values of oil was taken as a weighted cost (¢/kWh) based on

- use of diesel oil at 3,37 kWh/l,
- electrical equivalent of heating oil at 7,86 kWh/l,
- the current costs of diesel oil and heating oil, inclusive of transportation costs but excluding federal taxes (NCPC does not pay federal taxes),
- the ratio of the normal electric load to the heating load,
- the cost of capacity of new diesel generation at each community (expressed as cost/kWh of energy generation), taking into account the existing reserve diesel capacity of 100%, Table 2.1.

The cost of energy from the hydroelectric schemes were based on projected sales. These costs were calculated on the present worth of investment, operation and maintenance costs and the present value of projected energy sales over a 40 year project life. These calculations were summarised for both 6% and 8% discount rates. As the calculations take into account the fact that not all of the energy which can be produced by the hydro plant immediately is utilised, the cost of energy was therefore the effective cost.

2.3 PHASE TWO

In the second phase of the study, more detailed analyses were carried out on the most promising sites.

TABLE 2.1

EXISTING DIESEL SYSTEM

Cost of Capacity (for electricity) in 1984 Cdn $

Community	Load Factor	Energy per kW	Required Installation	Cost/ kW (#)	Annual Cost (*)		Value of Capacity (0)	
	% (1)	(kWh) (2)	(kW) (3)	($) (4)	($) (5)		(¢/kWh) (6)	
Discount Rate					6%	8%	6%	8%
Baker Lake	50	4 380	2	1 610	390	437	8,9	10,0
Coppermine	52	4 555	2	1 904	461	517	10,1	11,3
Fort Simpson	56	4 905	2	1 481	358	402	7,3	8,2
Frobisher Bay	61	5 344	2	1 307	316	355	5,9	6,6
Rae Lakes	47	4 117	2	2 615	633	710	15,4	17,2
Rankin Inlet	61	5 344	2	1 654	400	449	7,5	8,4

(#) Supplied by NCPC as the current cost of diesel installations (includes site work, buildings, fuel storage etc.)

(*) (3) x (4) x annual cost factor, given below:

Discount Rate	6%	8%
Uniform annual payment (20 year life)	8,72	10,19
Operation and maintenance	2,00	2,00
Overhead (35% of O&M)	0,78	0,78
Interim replacement	0,35	0,35
Insurance	0,25	0,25
Annual Cost Factor (%)	12,10	13,57

(0) $\frac{(5)}{(2)}$

Field Surveys

- Field surveys were completed for the most favorable sites, as determined from the first phase. The surveys were conducted to confirm regional geotechnical conditions, based originally upon air photo interpretation, and natural head. Additional hydraulic and, where possible, hydrologic data were also collected.

- The environmental and socio-economic impacts of the projects were investigated and the views of the communities ascertained.

Load Forecasts

- Load forecasts for the most favorable sites were revised for five conditions:
    - extension of the present electrical demand, with and without energy conservation;
    - extension of the existing electrical load plus heating requirements, with and without energy conservation;
    - extension of the existing electrical demand increased for improved lifestyle and heating requirements and decreased by energy conservation. This is the medium combined load.

- The hydroelectric projects were designed to meet the medium combined loads to the year 2024.

- Reference should be made to Section 3 of the Coppermine Development Appendix Report for a more thorough discussion of load forecasting.

Power and Energy

In calculating the power and energy potential of each site, the following decisions and assumptions were made:

- the on power date would be 1994;

- the hydro project would be designed to cater for the medium combined load. This assumes that the community will become energy conscious, and that future buildings will incorporate stricter energy conservation standards;

- the minimum installed capacity of the projects should correspond to the peak demand in 1994;

- the installation should be based on the peak load plus one unit, but there should be no less than two units to obtain both reliability and flexibility. This is conservative and assumes no diesel back up units on the system.

- the maximum size of the units should be the summer load divided by 0,6 to obtain good part load efficiency.

It was also assumed that the diesel generating units would be kept in good repair for emergency use. This, in effect, allows the diesel units to form part of the reserve capacity. However, the cost of doing this was not considered in the economic analysis. It was also assumed that all generating units were installed at once rather than phased in.

Project Costs

Capital costs were obtained by applying unit costs to specific quantities for the civil works, and from in house data for the electrical and mechanical equipment and works. Construction costs are expressed in 1984 dollars and have a precision of ± 20%.

The unit costs which were developed assumed that:

- unskilled labour would be obtained locally;

- local contractors would be used for road building and local transportation;

- a camp site would be constructed near the project site, i.e., away from the community;

- skilled labour would be imported.

The construction period was taken to be 3 years, especially because of the reduced working periods for those structures which are located in the river channels. Consequently, interest during construction was based on the assumption that the cash flows for the first, second and third year would be 20%, 45% and 35% of the construction cost, respectively, and that real interest rates varied from 6% to 8% p.a.

Since the construction is of a highly specialised nature, and since rock, sand and gravel are the only materials of local origin, it is unlikely that the amount of money which could be disbursed locally would exceed 15% of the construction cost.

Economic Comparisons

For each community, electricity is obtained from diesel generators and heat from the direct combustion of home heating oil. The cost effectiveness of each hydroelectric project was therefore obtained:

- by obtaining the effective cost of energy from the hydro plants and comparing it with the weighted cost of the existing methods of providing electricity and heat: the effective cost of the hydro energy was calculated by considering only the amount of energy which can be used, as indicated by the load forecast.

- by obtaining the present value of expenditures for diesel oil and home heating oil and the capacity value of the diesel generators and comparing it with the present value of the capital and all operating and maintenance costs of the hydro plant. The quantity of oil which would be required was based on the separate electricity and heating demand forecasts.

The calculations are inter-related and whilst the first method provides a cost index, the second gives the upper limits of expenditure for the hydro plant. If the cost index is equal to 1,0 then the hydro plant is as good as the existing method of providing the energy needs of the community.

An alternative economic analysis which considers the approach of "the project with and without the hydro plants", implies the use of additional diesel generators to meet the heating load. Since this method of providing heat is less efficient than the direct combustion of oil, then diesel generators would not be used for this purpose. Economic analysis using the method outlined above would seem to be an appropriate alternative. One noteable exception to this approach is where waste heat from the diesel units is used to heat buildings in the community. This is beyond the terms of reference of this study but is being investigated by EMR and NCPC.

2.4 PHASE THREE

Project Design

The selected site at Bloody Falls was re-examined to cater mainly for the normal electric load. In addition, to minimise the environmental impact of the project, no diversion dam was to be constructed across the river.

The load forecast of the second phase was re-used, but the transmission loss was reduced from 18% to 14% based on NCPC guidelines. Since no additional field information was available, the derivation of quantities and unit costs followed the same criteria as were used during the second phase of the Study.

Economic Comparison

There was substantial variation in the economic analysis of the project in this phase. The governing criteria were as follows:

- to assume that electrical energy in excess of the normal electric load could be used for space heating;
- the cost of a hydro-diesel system to cater for the projected load over the economic life of the hydro plant was to be obtained, and this cost was to be compared with the cost of all diesel system;
- the expansion of both the diesel system and the hydro-diesel system was to be made within a fixed degree of reliability;
- sensitivity tests varying both the cost of the project and the cost of oil were to be made using interest rates from 6% to 10%.

This present worth analysis was done with the use of a computer program and it provided internal rates of return, benefit cost ratios, the time needed to recover the investment, and the most suitable year to commission the hydro plant.

2.5 HYDROLOGY

Since most of the potential sites were not located near or at a streamgauging station, a regional hydrologic analysis applicable to all of the sites had to be done. The methodology is given below.

2.5.1 Data Base

The data which was used to evaluate the flows which could reasonably be expected at the various potential sites consisted of:

TABLE 2.1

GAUGING STATIONS USED IN STUDY

Gauge No.	Gauge Location	Period of Record	Drainage Area km2	Specific Yield l/s/km2
10JA002	Camsell River at Outlet of Clut Lake	33#, 34-35C, 63-64S, 65-82C	31 100	2.77
10PB001	Coppermine River at Outlet of Point Lake	64#, 65-82C	20 300	5.21
06LC001	Kazan River above Kazan Falls	60-64#, 65-70C, 71S, 72-82C	72 300	5.90
06LA001	Kazan River at Outlet of Ennadai Lake	62-63S, 64#, 65S, 67-78C, 79S, 80-82C	23 900	5.03
06MA002	Kitiyouuq Creek near Baker Lake	69-78C, 79-80S, 81-82C	433	5.73
10ED002	Liard River near the Mouth	72-82C	277 000	*
06MB001	Quoich River above St. Clair Falls	69-71#, 72-79C, 80#, 81-82C	28 700	5.34
10EC001	South Nahanni River above Clausen Creek	59-62S, 63-81C	33 400	*
10TE001	Sylvia Grinnell River near Frobisher Bay	71C, 72-82S	3 030	8.87 +
06MA003	Thelon River above Baker Lake	73-78C, 79S, 80-82C	154 000	4.64
10JC002	Thelon River above Beverly Lake	65-69#, 70-71S, 72-74C, 75-79S, 80-82C	65 300	*
10QA001	Tree River near the Mouth	69-82C	5 960	*
10FA002	Trout River at Fort Simpson Hwy.	69-82C	9 090	3.51
10GB001	Willow Lake River near the Mouth	64-82C	21 600	*

Legend

# - Miscellaneous recordings   33 = 1933 etc.
C - Continuous recording
S - Seasonal recording
* - Used for flood forecast only. Specific yield not calculated
+ - Based on one complete year of record (1971)

Source

Environment Canada, Water Survey of Canada
Reference Index, 1981 and Record Data Tapes 1984

- recorded flows from 14 gauging stations operated by Water Survey of Canada. These stations together with their drainage area, specific yield and period of record are given in Table 2.1;
- the hydrologic atlas of Canada;
- two previous engineering studies of the Northwest Territories, References 7 and 12.

2.5.2 Climate

Climate plays a decisive role in the life and geomorphological processes, and design and construction methods for projects in the northern latitudes. The climate of the study areas are both tundra and sub-arctic types; the two most southerly areas, namely Rae Lakes and Fort Simpson, fall into the latter category. Because of the northerly location of the areas, there is a great variation of the daylight hours as the year progresses. This variation for the most northerly area, Coppermine, and the most southerly area, Fort Simpson, can be seen in Figure 2.1.

The project areas lie in region where the mean monthly temperature varies from -33°C at Baker Lake in January to 17°C at Fort Simpson, but typically about 10°C for the other areas, in July. All of the areas register temperatures below freezing for 8 months of the year, January being the coldest month; in fact, the area around Baker Lake and Rankin Inlet is the coldest part of mainland Canada. July is the warmest month of the year for the study areas.

As can be seen in Figure 1.2, permafrost, either continuous or widespread discontinuous, is found in the study areas. The occurrence of permafrost has a distinct and severe effect on the design criteria and construction methods which must be adopted. Figure 1.2 also indicates the location of the tree line, north of which only tundra type vegation is found, namely lichens, mosses, sedges, herbs, and dwarf species of alder birch and willow. Rae Lakes has sub-arctic forests, for example black spruce, jack pine, poplar and willow. In the Fort Simpson area, boreal forest types are found, for example, aspen poplar, birch, pine, white spruce, willow.

The magnitude of the winds in the study areas vary from 14 kph to 31 kph.

2.5.3 Precipitation

During the eight months of winter, surges of cold, arctic air flow southwards with the accompanying low temperatures. The ability of the air to contain moisture at such low temperatures is very small and very little precipitation can occur under these circumstances. Most of the winter accumulation occurs when the moist air flows from the southerly direction. Figure 2.2 shows that the of precipitation in the mainland region of the Northwest Territories varies from about 150 mm per annum to about 300 mm p.a. The greater amount of precipitation in the Frobisher Bay area is due to its location, facing Frobisher Bay and the Atlantic Ocean, and hence there is a greater occurrence of the interaction of moisture laden air from the south with the cold, arctic, air from the north. The data for Figure 2.2 was obtained from Reference 7.

2.5.4 Evaporation

Evaporation and evapotranspiration in the study are quite small and this is indicated in Figure 2.3. The low evaporation is due to the long winters, small amounts of solar radiation, low temperatures and ice cover on the rivers and numerous lakes. The date of Figure 5.4 was obtained from Reference 12.

2.5.5 Runoff

Of the six study areas, only one did not have a streamgauging station on the associated river or on a nearby river. This was the Rankin Inlet area and the river in question was the Diana river. For the remaining rivers although there was a streamgauging station on the river being investigated, the location of the gauge was not at the intake site. Methods were therefore developed to transpose the available data to the intake site.

Figure 2.4 shows a regional runoff map of the area. This map was obtained from Reference 7, and the calculations which were made for its preparation was based on a short period of recorded flow. Up to date, 1982, information of recorded flow was used to check the validity of the isohyds. The check consisted of comparing the flows which should be obtained at established gauging stations, using the isohyds, with the measured flows. The results are as follows:

Gauge	Runnoff - mm		
	Recorded	Isohyds	Error - %
Camsell River	87,4	80	- 8,5
Coppermine River	164,3	156	- 5,0
Kazan River at Ennàdai	158,6	156	- 1,6
Kazan River at Kazan F.	186,1	210	+ 12,9
Kitiyouuq Creek	180,7	170	- 5,9
Quoich River	168,4	156	- 7,4
Thelon River at Baker Lake	146,3	149	+ 1,8
Trout River at Highway	110,7	122	+10,2

The agreement of the isohyds with the recorded flows are considered to be quite good for the study areas. This map was used to check specific yields for ungauged drainage areas.

In order to estimate the flow at an ungaged location, not only the specific yield, but also the shape of the hydrographs must be known. To establish specific yields for an ungaged location, those of the gauged areas, runoff, precipitation, evapotranspiration, and estimated runoff to precipitation ratio were all used to obtain the values given below. Estimates of runoff to precipitation were obtained using Figure 2.5. This graph was prepared by calculating the average precipitation, from Figure 2.2, and runoff, from the recorded daily flows, and plotting the ratio of runoff to precipitation against the latitude of the centre of the drainage basin.

For the projects which were analysed, and because of the need to store water for the production of power during the winter, the specific yields of the drainage basins under study are of prime importance. The analyses, as outlined above, allowed the adoption of the following specific yields:

Study Area	Location	Specific Yield
Baker Lake	Thelon R. at Baker Lake	4,63 l/s/km^2
	Unnamed river and Kitiyouuq Creek	5,23
Coppermine	Bloody Fall	4,70
Fort Simpson	Trout Lake	3,51
	Trout R. at Highway	3,51
Frobisher	Sylvia Grinnell River	8,0
Rae Lakes	Rae Lake	2,80
Rankin Inlet	Diana River	4,91

The recorded flows of some of the stations which were examined indicated that many of the rivers froze during the winter. Under the climatic conditions which prevail in the study areas, any lake or river which is less than 2,5 m deep would be frozen to the bottom in the winter. This condition allowed one part of the hydrographs to be plotted.

To plot the location of the peak flow, its time of occurrence was noted from the pattern of the gauged rivers, and from the time of break-up. The value of the peak flow was derived using Figure 2.6 which shows the relationship between the ratio of peak flow to average flow and the percentage of lakes occurring in the drainage basin. The area of the lakes were obtained from the available topographic map. A similar relationship is shown for the ratio of minimum flow to average flow.

Knowing the peak flow, average flow, based on specific yield, and minimum flow, it was possible to prepare a hydrograph of the ungauged locations.

2.5.6 Storage Requirements

The electric load shapes indicate that the power demand in the winter is about two to three times that of the spring and summer. This is a reverse of the flow pattern of the rivers, and hence the spring and summer flows must be stored for release during the winter.

The amount of storage which is required depends on the load and the configuration of the project. Three categories were evident and the storage requirements and river regulation for the projects were based on this categorization.

The first category is a two-lake system, natural and/or artificial, or an upstream lake with a large intermediate drainage basin between the lake and the intake of the hydroelectric plant. In this system, the spring and summer flows to the upstream lake must be stored and released over a period of seven to eight months of winter. Flow for the remaining period of the year was supplied by the downstream lake or the uncontrolled drainage area.

The second category was one where there was an upstream lake but no downstream lake or large intermediate drainage area. In this case, a part of the spring and summer flows was stored to provide winter flows.

The last category requires no storage since the minimum flow of the river is more than or adequate for the required power, but the river level was raised to obtain head.

Because of the size of the lakes and/or the values of the mean annual flow, the actual height of storage in the upstream lakes was relatively small. However, these had to be increased to gain head, in some cases, and a 2.3 m ice cover was allowed to satisfy intake requirements.

2.5.7 Flood Flows

The flood analysis was done using a regional technique consistent with the geomorphologic characteristic of the region. A predominant feature of the study area is the widespread occurrence of lakes which tend to dampen flood peaks and even out river flows.

Data from all of the stream gauges were used in the regional analysis. The maximum annual flood peaks for each of the stations were plotted on a log-normal paper to provide the 1 in 20 year (construction flood) and 1 in 1000 year (spillway design flood). Then the values of all the 1 in 20 year floods and all the 1 in 1000 year floods were plotted against drainage area. It was found that the floods from drainage basins in which major lakes accounted for less than about 15% of the total area tended to group together. Similarly, drainage basins which had major lakes covering more than 15% of the total area formed another group.

The resulting lines of best fit which summarises this situation are shown in Figures 2.7 and 2.8, and in the following table.

Category	1 in 20 year flood	1 in 1000 year flood
Lakes greater than 15% of the drainage basin	$Q = 0,016\ A^{1,04}$ $r^2 = 0,94$	$Q = 0,036\ A^{0,99}$ $r^2 = 0,94$
Lakes less than 15% of the drainage basin	$Q = 0,63\ A^{0,81}$ $r^2 = 0,94$	$Q = 1,41\ A^{0,79}$ $r^2 = 0,97$

where Q = flood flow in m^3/s
A = area of the drainage basin in km^2
r = coefficient of correlation

As can be seen from the results, the coefficient of correlation of the relationships is quite high. These formulae were used to size the spillways and estimate the construction floods for the various schemes. Some of the floods were routed through the lakes at the intakes where it was appropriate.

SECTION 3 BAKER LAKE

3.1 GENERAL

Baker Lake is an Inuit community which is located on the north shore of Baker Lake near the mouth of the Thelon River at 64°-18'N latitude, 96°-03'W longitude. The community is not far from the geographical centre of Canada and it is surrounded by a number of hydroelectric sites of varying potential. It is also easily accessible by ship via Hudson Bay, Chesterfield Inlet and Baker Lake.

3.1.1 Population

In 1981 the population at Baker Lake was 955 as recorded by Statistics Canada. There is an even balance between male and female, and the predominant cultural group is the Inuit numbering 850. The largest age cohort was found between the ages of 0 and 19 in 1981. Recent statistics reveal that Baker Lake is growing at a rate of 2.5% p.a. Therefore an estimated 1 000 people presently live in Baker Lake. Of this number it is estimated that 580 people, split evenly between male and female, are between the ages of 15 and 64.

3.1.2 Employment and Income

The economic base in Baker Lake is essentially traditional consisting of hunting, fishing and trapping. Other recently introduced economic activities include arts and crafts and tourism. Baker Lake is also well positioned as a centre from which mineral exploration can take place in the Keewatin District. Rock types found in the Keewatin District have the potential to bear such minerals as uranium, gold, silver, iron, zinc, nickel, copper, cobalt and lead.

Transportation into and out of Baker Lake is limited to air and sea routes. There are no road connections to other centres of habitation.

Full time employment varies between 160 in the winter to 180 during the summer with approximately 85% of those employed being male. At present 34 people are actively looking for work. The potential labour force is estimated at 425 people giving rise to an unemployment rate of approximately 60%. Per capita income in 1981 was recorded at $4 049 and consumer prices were 60%-70% higher than in Winnipeg.

3.1.3 Housing

Housing consists of 175 NWT Housing Corporation units with GNWT staff units of 20 single family units and 2 duplex units. Federal housing consists of 14 single family units. Approximately 15 housing units were under construction in 1984. Heating is by means of fuel oil supplied by POL.

3.1.4 Commercial

Retail and wholesale trade is very limited with retail goods supplied by the Bay, the Miksuquik Sewing Centre, video outlets, and the Baker Lake Ladies Group Store. Commercial accommodation is available at the Iglu Hotel and the Baker Lake Lodge. Tourism is an active enterprise with outfitters who cater for fishing and photography expeditions. Arts and crafts supplies and sales are available through the Sanavik Cooperative Association store. Petroleum products are distributed via a private distributor.

3.1.5 Industrial

There are three to four contracting companies which supply heavy equipment, undertake building and site work, and provide local cartage and expediting services. Uranium exploration is presently being carried out in the area and Baker Lake is used as a logistics centre.

3.1.6 Recreation

The community has a meeting hall, covered arena, school gym and a summer pool.

3.1.7 Social Services

The community has a school which offers education from kindergarten to grade 10, and had a 1983/84 enrollment of 287 students. There is also a small adult educational centre with one resident instructor.

Medical facilities consist of a three bed/two bassinet nursing station. The station is staffed with three nurses and one dental hygenist. Two people staff the Social Services Office and there is an Alcohol Education Committee. The Bahai House, and Christian Arctic Fellowship Churches are also present along with the traditional Anglican and Roman Catholic missions.

There is a two man RCMP detachment, justices of the peace and coroners. Fire protection is supplied by means of a 15 person volunteer fire brigade and one pumper truck.

3.1.8 Transportation

Baker Lake has a 1 280 m gravel runway, new air terminal building, and minimal navigation aids. Commercial air service is supplied by Calm Air out of Rankin Inlet and Churchill. There also is an unlicensed float plane base with limited services.

Barge service for community resupply is provided by NTCL out of Churchill, Manitoba.

Surface transport is provided by taxi and there are no roads external to the community.

3.1.9 Water, Sewer, Roads, Solid Waste

Water is supplied to the community from Baker Lake via an intake and wet well. Sometimes small fishes pass through the screens at the pump intake, and the pump has been known to draw brackish water. Some residents do not use the present water supply and haul water themselves directly from the lake.

The MOT maintains a piped water distribution system which serves the nursing station, MOT houses and the compound. The remainder of the hamlet is serviced by water truck delivery.

Sewage holding tanks are pumped out and sewage, as well as sewage bags, are trucked to Finger/Airplane Lakes. A previously installed macerator/lift station in the community has not been used for some time due to operating problems during the winter. The treated effluent from this lake system is eventually discharged into Baker Lake after about 5 years.

Considerable maintenance of the gravel roads is required as a result of spring thaws which can wash several sections of road out each year.

Solid waste is collected from steel drums and disposed 3 km east of the hamlet at the Finger Lake site.

3.1.10 Lifestyle

The lifestyle in Baker Lake may be described as Inuit traditional. There has been a slight change toward increasing wage employment, but social assistance provides a noticeable source of income. Recent wage/contract employment other than government and tourism has been in the mineral exploration sector.

The importance of traditional pursuits is highlighted in Table 3.1. This shows the total dominance of caribou (96%) in the Inuit diet of traditional game. To replace the total amount (247 209 kg) of meat/fish with beef at say $10/kg would represent some $2.5 million annually or $11 500 per household. The caribou thus accounts for some $11 000 per household per year in food, and also provides an important source of materials for tents, clothes and artwork.

Quite apart from the economics, caribou hunting is an important way of life to the Inuit. The pursuit of the caribou is a year round activity and plays a crucial part in the community's well-being. The community would be hard pressed to trade-off any significant impacts upon the caribou for economic benefits such as a cheaper and more reliable power supply.

TABLE 3.1

Estimated Baker Lake Harvest (1982-83)

Species	No.	Estimated Avg. Edible Weight (kg)/Species	Total Est. Edible Weight Available Each Year (kg)	%
Caribou	4 945	48,0	237 341	96
Musk-Ox	12	110,0	1 331	1
Ringed Seal	1	14,3	14	-
Lake Trout	3 236	2,4	7 852	3
Whitefish	276	2,4	671	-
		Total	247 209	100

Source: R.L. Gamble, A Preliminary Study of the Native Harvest of Wildlife in the Keewatin Region, NWT, Fisheries and Oceans, 1984

3.2 EXISTING ENERGY LOADS

3.2.1 Electric

The existing electrical load in 1982/83 amounted to 3751 MWh with an annual load factor of 48%. Sales amounted to 3369 MWh with the domestic market conttributing 52%, commercial 37%, and wholesale and street lights accounting for the remainder. There were no industrial sales. Average annual growth over the past 6 years has averaged 1,8%.

3.2.2 Heating

Space heating in Baker Lake is supplied by oil furnaces and in 1983/84, 493,283 gallons of heating oil were consumed in Baker Lake. This is equivalent to approximately 14,240 MWh of heat as an electrical load. On the basis of sales, this heating load is roughly 3,8 times the normal electric load.

3.3 LOAD FORECASTS

The load forecast for Baker Lake was carried out in some detail since the Baker Lake project was selected for field investigations and more detailed study. The methodology employed in the load forecasts for Baker Lake was based on the criteria and assumptions stated in Sections 2.2 and 2.3. In preparing the load forecasts the following was taken into account:

- the design capacity was obtained by adding the peak daily loads for normal electrical use to the electrical equivalent of peak daily heating loads.
- Annual electrical load factors for Baker Lake was taken as 0,50, based on historical plant data.

Conservation measures were assumed as follows:

. Electrical	20% reduction by 1994 based upon present comparison of government and non-government domestic consumption per customer.
. Space Heating	20% reduction by 1994 based upon better insulation through retrofit and public education by the NWT Housing Corporation.

Lifestyle factors are increasing electrical consumption in NWT communities. This led to the selection of a ceiling of electrical consumption to which the communities could reasonably be expected to reach, based upon the consumption patterns exhibited by larger communities with similar functions. These assumptions are summarized below:

- 6,0% annual growth in domestic consumption to a maximum of 2600 kWh/capita; then 4,0% to 3000 kWh/capita; then 2,0% thereafter;
- 2,5% annual growth in commercial/institutional consumption to 1994; 2,0% thereafter.

Population forecast at a natural growth rate of 2,5% given in Table 3.2.

3.3.1 Energy and Capacity

The average annual energy to be generated over 40 years has been calculated for each of the five scenarios given in Section 2.3. Based on the load factors for electric and heating loads, the corresponding peak design capacity for selected years were determined. The results are given in Table 3.3 and shown in Figure 3.1.

Table 3.3 illustrates that the required design capacities vary from about 1 MW for the low electrical load scenario in 1984 to 12,5 MW for the high combined load scenario in 2024. The greater impact of conservation measures with regard to heating when compared to increases in normal electric consumption due, for example, to improved lifestyle is clearly demonstrated. However, for the medium combined load, which has been used as the hydro plant design criterion, the useable plant capacity varies from about 5,5 MW in 1994 to about 10 MW at the end of the economic life of the project in 2024.

3.3.2 Load Shape

The average monthly load requirements for the medium combined load are given in Table 3.4. Figure 3.2 shows the variation for the combined load for 1994 and demonstrates that the load requirements in March and April are relatively high at a time when the river flows are low. This graph also shows that the loads are relatively low from June to August when the river flows are high.

TABLE 3.2

POPULATION FORECAST - BAKER LAKE

Year	Population
1982	956
1983	979
1984	1 003
1985	1 027
1986	1 052
1987	1 078
1988	1 104
1989	1 131
1990	1 159
1991	1 187
1992	1 216
1993	1 246
1994	1 276

Computer rounding has occurred.

TABLE 3.3

LOAD FORECAST - BAKER LAKE

	Low Electrical Load		Base Electric Load		Low Combined Load		Medium Combined Load		High Combined Load	
Year	Gen (GWh)	Design (MW)	Gen (GWh)	Design (MW)	Gen (GWh)	Design (MW)	Gen (GWh)	Design (MW)	Gen (GWh)	Design (MW)
1984	4,153	0,94	4,153	0,94	18,800	5,23	18,934	5,26	18,934	5,26
1989	4,229	0,96	4,699	1,07	19,143	5,32	19,727	5,46	21,854	6,05
1994	4,253	0,97	5,316	1,21	19,256	5,35	20,151	5,56	24,965	6,90
1999	4,696	1,07	5,870	1,34	21,256	5,91	22,249	6,14	27,563	7,62
2004	5,185	1,18	6,481	1,47	23,468	6,53	24,565	6,78	30,432	8,41
2009	5,724	1,30	7,155	1,63	25,911	7,21	27,121	7,48	33,599	9,29
2014	6,320	1,44	7,900	1,80	28,608	7,96	29,944	8,26	37,096	10,25
2019	6,978	1,59	8,723	1,99	31,586	8,79	33,061	9,12	40,957	11,32
2024	7,704	1,75	9,630	2,19	34,873	9,70	36,502	10,07	45,220	12,50

TABLE 3.4

BAKER LAKE

Average Monthly Loads (MWh)

Medium Combined Load

	1994			2009			2024		
Month	Electric	Heating	Total	Electric	Heating	Total	Electric	Heating	Total
Jan	561	2 159	2 720	756	2 907	3 663	1 016	3 912	4 928
Feb	504	1 935	2 439	680	2 604	3 284	914	3 504	4 418
Mar	509	1 950	2 459	687	2 624	3 311	923	3 532	4 455
Apr	442	1 440	1 882	596	1 938	2 534	802	2 608	3 410
May	350	1 034	1 384	471	1 393	1 864	634	1 874	2 508
Jun	283	570	853	381	767	1 148	513	1 032	1 545
Jul	293	300	593	395	403	798	531	543	1 074
Aug	324	345	669	437	464	901	587	624	1 211
Sept	386	645	1 031	520	868	1 388	699	1 168	1 867
Oct	442	1 095	1 537	596	1 473	2 069	802	1 983	2 785
Nov	499	1 574	2 073	673	2 119	2 792	905	2 852	3 757
Dec	551	1 950	2 501	742	2 624	3 366	998	3 532	4 530
Total	5 150	15 000	20 150	6 940	20 190	27 130	9 330	27 170	36 500

Note: Rounding has occurred.

3.3.3 Additional Load

During the course of the study, it became apparent that there could be an additional peak load of 4 MW and an energy requirement of 20 GWh p.a. This load would come from the mining company, Urangellschaft Canada Limited, which has been exploring in the area for uranium. The company would only be interested in purchasing the energy if it could be provided for less than they would normally have to pay for electricity and/or heating. This load of 4 MW has not been included in the economic analysis of the project, since there are no firm plans by the company at this time to implement the mining project.

3.4 POTENTIAL SITES

3.4.1 Hydrology

Basically, two schemes were considered for the Baker Lake community, Figure 3.3. The first scheme and its variation require no flow synthesis because there is a gauge on the Thelon river at Baker Lake. The gauge indicates a minimum winter flow of 225 m^3/s, Figures 3.4 and 3.5. This flow was taken as the design flow for the scheme on the Thelon river.

The second scheme, which will be referred to as the Lake Scheme, requires an evaluation of the specific yield of an unnamed river which has been used. This lake scheme also utilises flow from the Kitiyouuq Creek on which there is a gauge.

The Lake Scheme commands a drainage area of 3240 km^2 and a specific yield of 5,23 $l/s/km^2$ was adopted. This specific yield was adopted by considering the specific yields of the nearby rivers, namely:

- Thelon river at Baker Lake - 4,63 $l/s/km^2$ from 154 000 km2
- Kazan river at Kazan Falls - 5,90 $l/s/km^2$ from 72 300 km^2
- Kazan river at Ennadai outlet - 5,04 $l/s/km^2$ from 23 900 km2
- Quoich river at St. Clair Falls - 5,33 $l/s/km^2$ from 28 700 km^2
- Kitiyouuq creek near Baker Lake - 5,73 $l/s/km^2$ from 433 km2

The average flow of 16.95 m3/s was taken for the lake scheme and allowing for 10% losses and evaporation, a design flow of 15.16 m^3/s was adopted. It was assumed that storage for the winter months could be stored in the two lakes having areas of 40 km^2 and 95 km2 for release during the winter months. The derived average flows and dimensionless, daily flow duration curves are shown in Figures 3.6 and 3.7, respectively.

3.4.2 The Lake Scheme

This storage scheme utilises the warm season runoff into Kitiyouuq Creek and the Unnamed River for use during the cold season. Overflow rockfill dams would be constructed across each river and the flows of the two rivers would be diverted north-easterly to the intake area on the right bank of the Thelon River. The intake would be located in a small saddle between the 60,96 m (200 ft) contour above the river. The estimated elevation of the Thelon River at the location of the powerhouse is 22,8 m, whilst that at the intake is 65,8 m. The lake on the Kitiyouuq Creek would be raised from a probable natural level of 59,4 m by the dam to 65,8 m to allow the water to pass over the saddle into the intake.

The lake on the Unnamed River would be raised from 71,6 m to 74,6 m by the dam and control structure between the two lake systems. As the Unnamed River commands the larger drainage area and lake, most of the regulation would be done in this river system. A control structure would be located between the two lake systems to regulate winter releases into the smaller lake system on the Kitiyouuq Creek. Provision would be made to cut a suitably sized channel between the two lake systems.

The maximum turbine flow of 15,2 m^3/s would be passed to the powerhouse by an insulated pipe or tunnel 1500 m long. The total power output from the two turbo-generators would be about 5 MW from a net head of 42 m.

3.4.3 Thelon Dam Scheme

This scheme is labelled Alternative 2 on Figure 3.3, and would require the construction of an overflow, rockfill dam across the Thelon River in the environs of Tupik Lake. The river elevation is about 12,7 m and the 11 m high overflow dam would raise the river level to 21,6 m. This is slightly below the river elevation at the powerhouse of the Lake Scheme.

The advantages of this scheme are that storage is not required as the January flow of about 355 m3/s is adequate. It also requires a shorter transmission line to the Baker Lake community, and a shorter access route. The recorded minimum flow is 225 m3/s.

The powerhouse would be located on the left bank of the river and would house five turbo-generators each rated at 3,0 MW and operating under a head of 6,1 m. Initially, two machines could be installed and the remainder as the load increases.

It will be noticed that the river level has been raised to a level; so as not to interfere with a variation of the Lake Scheme as described below, the Thelon diversion scheme. In other words, the upstream water level of the Thelon dam scheme is slightly lower than the tailrace level of the Thelon diversion scheme.

3.4.4 Thelon Diversion Scheme

The Thelon River discharges into Shultz Lake before finally ending its course in Baker Lake. As Figure 3.3 shows, it is possible to divert the Thelon River into the Kitiyouuq Creek of the Lake Scheme and create a sizeable power development. The Lake Scheme intake and dam on the Kitiyouuq Creek are common to this alternative and that of the Lake Scheme. The diversion of the Thelon river has been assumed to be achievable by a tunnel and canal system, but field investigations would have to be done to determine the proper conveyance system.

It is estimated that the firm power output from this scheme, using only the minimum flow of the Thelon river, is about 60 MW. This power would conceivably be used to service Baker Lake, Rankin Inlet and Chesterfield Inlet and any other community in the area. If the three main communities are linked, a transmission line totalling 385 km will be required. This possibility has been examined on the assumption that the power output will be used to satisfy the normal electrical load and the space heating load for these three communities.

It should be noted that for the Lake Scheme the spring and summer river flows are stored for winter releases. The Thelon diversion scheme augments this winter power flow. This, in effect, means that flow in the Thelon river between the outlet of Shultz Lake and Baker Lake will be nearly normal only during the spring and summer.

The cost of this scheme is about 350 million dollars and could not be justified by the present or projected loads of Baker Lake, Chesterfield Inlet and Rankin Inlet.

3.4.5 Preferred Scheme

At the end of the Phase 1, the characteristics and economic evaluation of the Thelon dam scheme and the Lake Scheme were found to be as shown in Tables 3.5 and 3.6 following.

The preferred scheme chosen for detailed investigation in Phase 2 of the study was therefore the Thelom Dam Scheme. This was due to the fact that the Thelon Dam Scheme was cheaper to construct, and that this scheme could serve both the electrical and heating loads over 40 years, whereas the Lake Scheme could meet the load for only 31 years. Therefore, further discussion will be limited to the work done on the Thelon Dam Scheme during Phase 2.

3.5 GEOTECHNICAL

3.5.1 General

The Thelon river has incised a single channel into the granitic rock which underlies much of the lake-spotted tundra in the Baker Lake region of the eastern arctic (photo 1). One of these lakes near the dam site is Tupik Lake (photos 2 and 3). Generally, the bedrock is covered with a mantle of granular till. Within the region, numerous lakes range in size from several square km to small thermokarst ponds (photos 3 and 4). These latter features are frequently associated with moraine plains and areas of thicker organic (peat) terrain. Such deposits often occupy lower lying ground between rock outcrops and are manifested by the thermokarst lake features. The areas of till plain and significant peat (organic terrain) will tend to be ice rich and may therefore present more troublesome foundation conditions for most rigid structures. Elsewhere, foundation conditions will generally be good despite continuous permafrost. Map 1 indicates the occurrence and extent of the rock and soil types which are found in the study area. This mosaic has been terrain typed according to the accompanying legend.

TABLE 3.5

PROJECT CHARACTERISTICS

BAKER LAKE DEVELOPMENTS - PHASE 1

Item		Lake Scheme	Thelon Dam Scheme
Drainage Area	(km2)	3 240	15 600
Average Runoff	(mm)	165	146
Average Natural Flow	(m^3/s)	16,9	722,1
Maximum Plant Flow	(m^3/s)	30,0	225
Upstream Elevation	(m)	65,8	21,6
Downstream Elevation	(m)	22,8	12,7
Gross Head	(m)	43,0	8,9
Net Head	(m)	41,0	8,4
Interlake Channel	(m)	4 000	-
Pipe/Tunnel			
- length	(m)	1 500	100
- diameter	(m)	--	4,8
Installed Capacity	(MW)	5,0 (Initial)	6,6 (Initial)
Energy Capability	(GWh p.a.)	38,7	117,1

TABLE 3.6

ECONOMIC EVALUATION

BAKER LAKE DEVELOPMENTS - PHASE 1

Item	6 %		8 %	
	Lake Scheme	Thelon Dam Scheme	Lake Scheme	Thelon Dam Scheme
Present value (P.V.) of construction cost and annual cost (Millions 1984 dollars)	55,84	41,60	54,17	40,39
P.V. of energy sales (GWh over 40 years)	377,2	380,5	285,3	287,0
Effective cost of hydro energy (¢/kWh)	14,8	10,9	19,0	14,1
Equivalent value of diesel generation and heating oil (¢/kWh)	10,9	10,9	11,2	11,2
Cost index	0,74	1,00	0,59	0,79

3.5.2 Thelon River Dam

The proposed structure is envisioned as an overflow dam providing a maximum gross head of 10 m. Such a structure would be located at a point immediately upstream of the left hand bend, 500 m upstream of the outlet from Tupik Lake. At this point both abutments will be in granitic rock outcrops and the channel is undoubtedly underlain by rock at shallow depth. The upper channel banks through this reach are veneered with colluvium but at generally higher elevations than will be achieved by the raised river level.

3.5.3 Reservoir

The Thelon river banks upstream of Tupik Lake are either formed by or controlled by rock outcrops for the most part. The lower banks are commonly shallow sloped beaches partly armoured by cobbles and boulders derived from the colluvium and till. Although the upper slopes are frequently in till or a veneer of colluvium and are susceptible to bimodal flow slides and solifluction type movements, it is not anticipated that the proposed increase in river level will adversely effect these slopes in any significant way.

3.5.4 Powerhouse

A powerhouse located on the left bank immediately downstream of the bend will be founded on granitic bedrock which is presently overlain by granular armouring of the lower river bank. A powerhouse located in the left bank will be in massive granitic rock.

The rock at this location appears to be massive with less distinct jointing and fracturing than at Bloody Falls on the Coppermine River.

3.5.5 Tunnel

A tunnel through the left bank at this location would be drilled through massive granitic rock and not likely susceptible to excessive seepage.

3.5.6 Borrow Sources

Local tills appear to be rich in coarse grained soils and may therefore provide a good source of construction material. There are also eskers 3 km east of the proposed dam site and several raised beaches 10 km south of the site which are potential sources of construction materials. These sources should be investigated by test pitting at a latter stage to determine quality and quantity of material available from each source.

3.5.7 Transmission Line Route

The pole line contemplated to run from the proposed powerhouse to the Baker Lake townsite should be routed at least one km northeast of the river to avoid the present and potential landslide features along the river bank. These features are not prevalent along the left bank downstream of Tupik Lake, but it will be prudent to anticipate that some instability may occur where the sloping drift is ice rich. Individual towers will have to be anchored in bedrock to resist the frost-jacking forces of the active layer.

3.6 PRELIMINARY DESIGN

3.6.1 Diversion Works

The layout and preliminary design of the permanent works, which extract only a very small portion of the energy potential of the river, were dictated by the following considerations:

- the need to reduce costs by utilising the large and costly diversion works, as far as possible, as a part of the permanent works;

- the need to reduce the height of the dam by utilising the entire minimum flow of the river during March and April;

- the need to deal with the ice floes effectively.

The standard design criterion for the diversion works would be to pass the 1 in 20 year flood which is estimated to be 3400 m^3/s. To cater for a flood of such magnitude, not only would the cofferdams and diversion tunnels be quite large, but the cost of constructing such works would make the project uneconomic. If a major portion of the energy potential of the river was being extracted, then normal diversion works procedures could apply. However, for the amount of useable energy, the height of the permanent dam is very much smaller than the height of the cofferdam which caters for the full 1 in 20 year flood.

To achieve a reduction in the size of the cofferdam and diversion works, it must be accepted that no work can be done in the river during ice break-up and during the peak river flows. As Figure 3.4 shows, this would indicate that work in the river would start during the second half of July and continue for about 3 months. It also means that any smaller cofferdam would have to be designed to withstand overtopping and the passage of ice over it.

Figure 3.8 shows floods of various return periods for the Thelon river at Baker Lake. The recorded range of flood peaks vary from about 2600 m^3/s to 3600 m^3/s; the flow of 6000 m^3/s recorded on 22 June 1984 appears to have a return period of about 37 years. The diversion tunnel has therefore been designed to cater for flows of about 1550 m^3/s, corresponding to a total area of 242 m^2; this is much smaller than the size which would be required for the full 1:20 year flood, and the cofferdam is much lower. The length of the diversion tunnel is about 450 m. Because the cofferdam across the river has been reduced in size, it has been incorporated into the main overflow rockfill dam. In fact, it forms the downstream toe of the main dam.

3.6.2 Layout

Since the minimum flow of the river is large, namely 225 m3/s, a layout could be considered in which a dyke or spur from the right bank of the river is constructed to some point less than the width of the river. Such a structure could conceivably be used to divert flow, at a level above the normal river level, into a penstock on the left bank of the river. Similarly, it is possible to consider a dam and powerhouse which occupies only a part of the river - such a design assisting in solving the diversion problems.

Both of these layouts suffer from the disadvantage of having an incomplete structure across the river, namely, that the minimum flow would pass mainly down the river rather than through the turbines. The result would be that the powerhouse would most likely be non-operational during this period, since about 30% of rated turbine flow is required to operate the turbines rather inefficiently. The preferred layout is therefore one which would capture the entire or most of the minimum river flow, thus reducing the height of the permanent dam and allowing the generation of energy during periods of low flow.

The layout, Figure 3.9, uses most of the diversion tunnel as the power tunnel. The smaller portion is about 8,5 m in diameter and 170 m long and from it up to six penstocks lead to an underground powerhouse.Both the upstream and downstream ends of the diversion tunnel are fitted with gates to prevent water from entering it during the construction of the powerhouse. During the operation of the power plant, the diversion tunnel could also be used, if necessary, as an additional floodway. The underground powerhouse is clearly one option to counter structural ice damage, by avoiding it; it is reported locally that 18 m of ice and snow in the river is not unusual.

The main dam has been designed as an overflow rockfill dam which utilises some of the excavation from the diversion tunnel. To relieve uplift there are longitudinal spacings between the precast, concrete armour plates on the downstream slope. These plates are necessary to prevent damage to tne dam during spring break-up, and the relatively mild slope should allow easy passage of the ice. A similar structure has been built in the Soviet Union, Ref 31. The magnitude of the rock sizes, not less than 1,5 m, and the 1:1000 year flood, 15 500 m3/s, have been used to determine the downstream slope of the dam. Figure 3.10 shows a cross section and details of the dam.

On the left bank of the dam there is provision to operate a boat slide using rollers and a counterweight, and a fish lock. The preliminary design of the fish lock, which has been used for other species of fish, has its exit and entry openings below the expected ice level to cater for possible movement of fish in the winter. Figures 3.11 and 3.12 show alternative power station layouts.

To construct the permanent works, six cofferdams are needed:

- two, one upstream and one downstream, to construct the diversion tunnel and tailrace;
- one to isolate an area on the left bank of the river to construct the fish passage; boat slide and interface structure;
- two to construct the permanent dam;
- one to excavate the tailrace.

Alternative layouts utilizing a concrete dam rather than an overflow rockfill dam were also investigated. However, the concrete dam alternative was ruled out from further investigation on the basis of cost.

3.7 POWER AND ENERGY

Since the project utilises the minimum flow in the Thelon river, energy from the development is available all year round, i.e., it is firm energy. The smallest practical hydro plant which uses all of the minimum river flow and the minimum head required to operate a commercial turbine produces more energy than that required by the community to year 2024. There is therefore no difficulty in meeting the forecasted energy demand, but to cater for the swings in the heating load during the cold months, generating units in excess of those needed to meet the energy demand are needed. Additional capacity is also needed in the form of one extra unit, over and above what is required to meet the peak load, to ensure the reliability of the plant in such a relatively remote area.

Since the peak demand, not energy, is the controlling factor, plants of various sizes designed to meet the peak load in various years were examined. Also, since a cost trend was required, the head, hence the height of dam, was varied and thus the resulting flow required to obtain a given output was fixed. The maximum flow which could be used was governed by the range of turbine-generator packages which are available on the market.

The table below shows a preliminary sizing of the generating units to meet the peak power demand in various years. In every case the station flow is less than the minimum river flow of 225 m^3/s and the combinations which have been examined are not intended to reflect any optimization.

Year	Load Demand		Net Head	Station Flow	Max. generation possible	Generating Units		
	Energy (GWh p.a.)	Peak Power (MW)	(m)	(m^3/s)	(GWh p.a.)	Required (No)	Installed (No)	Size (MW)
1994	20,2	5,6	3,56	198	46,7	3	4	2,0
2004	24,6	6,8	5,34	160	56,6	3	4	2,3
2014	30,0	8,3	7,12	147	69,3	3	4	2,8
2024	36,5	10,1	8,90	143	84,3	4	5	2,6

As the table above shows, the maximum amount of energy which can be generated far exceeds the demand. The size, and hence number, of the units was controlled by the variation between the peak January load and the low summer load. The low summer load is about 22% of the January load (Table 3.4), and hence the machines operate above 60% part load in the summer. Figure 3.13 shows how many 2,3 MW units must be used to meet the load to year 2024, and in which years new units must be installed. While only two units are needed to meet the energy demand, five are needed to meet the swings in the peak load caused by temperature variations.

3.8 PROJECT EVALUATION

3.8.1 Cost Estimates

Cost estimates were prepared for four developments with net heads varying from about 4 m to about 9 m. This allowed a cost trend to be established for plants of different maximum energy and peak power capabilities.

The project costs, using a discount rate of 6% p.a. for calculating the interest during construction, are summarized given in Table 3.7 below. A substantial part of civil works cost rests in the diversion/power tunnel and the main dam. The cost of the diversion works vary from about 40% to 49% of the civil works cost, or from about 11% to 19% of the construction cost. Similarly, the cost of the main dam varies from about 22% to 29% of the civil works cost, or 6% to 11% of the construction cost.

It is clear that the single most important civil works item is the diversion works. In terms of absolute value, the diversion cost varies only by about $0,45 million, but the cost of this item increasingly dominates the construction cost as the plant size decreases. The cost breakdown demonstrates that maximum advantage should be taken of the civil works cost by making the plant as large as is economically possible, assuming that the energy can be used.

The Table also shows that the cost/kW decreases as the capacity increases.

TABLE 3.7

CAPITAL COST SUMMARY FOR ALTERNATIVE INSTALLATIONS AT BAKER LAKE (1984 Dollars)

COST ITEM	CAPITAL COST (millions of dollars)			
	10,4 MW	8,4 MW	6,9 MW	5,6 MW
Civil Works				
Access	1,500	1,500	1,500	1,500
Cofferdams	3,760	3,760	3,760	3,760
Main dam	6,590	5,208	4,501	3,154
Fish lock	1,197	0,916	0,664	0,473
Boat lift	0,150	0,150	0,150	0,150
Diversion tunnel	14,650	14,259	13,859	13,547
Power tunnel	1,230	1,206	1,046	0,996
Penstock	0,788	0,591	0,591	0,394
Powerhouse	3,672	3,350	3,351	3,124
Tailrace	1,760	1,840	1,920	1,920
Sub-total	35,297	32,780	31,342	29,018
Electrical and Mechanical				
Turbines	3,908	3,147	3,221	3,115
Generators	2,306	1,877	1,701	1,460
Miscellaneous equipment				
Electrical	1,325	1,074	0,935	0,786
Mechanical	1,652	1,388	1,413	1,377
Intake Equipment	1,183	1,022	0,950	0,814
Outlet equipment	1,582	1,582	1,582	1,582
Transmission line	1,095	1,095	1,095	1,095
Sub-total	13,051	11,186	10,897	10,230
Indirect costs	4,765	4,425	4,231	3,917
Engineering and management	5,311	4,839	4,647	4,316
Contingencies	5,842	5,323	5,113	4,748
Construction cost	64,266	58,553	56,230	52,229
I.D.C. (6%)	5,353	4,877	4,684	4,351
TOTAL CAPITAL COST	69,619	63,430	60,914	56,580
Cost/kW	$6,694	$7,551	$8,828	$10,103

The estimated peak labour force is about 220. Also, the estimated disbursements in the community vary from about $8 million to about $10 million depending on the size of the project.

3.8.2 Cost Effectiveness

In Section 3.3, the load forecast for Baker Lake was given for both the normal electric load and the heating load. The present values of energy sales for various discount rates are shown for the medium combined load in Figure 3.14.

The present value of diesel oil and home heating oil which would be required from 1984 to 2024 was calculated using the following data:

- 51,51¢/l for the cost of diesel oil;
- 55,0 ¢/l for the cost of home heating oil;
- 0,303 l/kWh for the diesel generator;
- 0,130 l/kWh for the electrical equivalent of home heating oil. This value is based on the calorific value of the oil and standard energy and efficiency factors.

The results of these calculations, together with the capacity value of the diesel generators, are presented graphically in Figure 3.13 for discount rates of 6%, 8% and 10% p.a. The capacity value is based on both the cost of producing electricity and the cost of diesel oil. Also, the cost of producing electricity was based on the unit cost/kW of erecting a new diesel station, including a 100% reserve diesel capacity, and the cost of diesel oil. The weighted cost of energy for both electricity and heat, as provided by the existing methods, was calculated by taking the ratio of the forecasted heating load to the normal electrical load as 2,91 for the medium combined load. These various costs are shown in the following table.

Discount Rate (%)	Value of Energy - ¢/kWh				
	Diesel Plant	Diesel Oil	Electricity Cost	Heating Cost	Weighted Cost
6	8,9	15,6	24,5	7,2	11,6
8	10,0	15,6	25,6	7,2	11,9

Figure 3.15 clearly shows that for the existing load and irrespective of the discount rate, expenditures on the hydro project outweigh those which would be incurred if the existing methods of providing electricity and heat are maintained.

The present values of the capital, operating and maintenance cost of the four hydro development alternatives over a 40 year economic life and a discount rate of 6% p.a. are shown in Table 3.8, below. These present values of expenditure together with the present value of useable energy allow the effective cost of energy to be calculated; these costs are also shown in the Table. It should be noted that since the plants produce more energy than can be used, then the present value of useable energy is the same for each alternative. Also, this table presents the project in its most favorable position by using the lowest discount rate of 6% and only 80% of the estimated construction cost.

TABLE 3.8

THELON DAM SCHEME

BAKER LAKE DEVELOPMENT

COST EFFECTIVENESS
(Based on 80% construction cost)

Discount rate = 6% p.a.

Item	Cost in $ x 10^6			
	Alternative 1 10,4 MW	Alternative 2 8,4 MW	Alternative 3 6,9 MW	Alternative 4 5,6 MW
Capital Cost (based on 80% construction cost)	55,70	50,75	48,73	45,26
Present values (P.V.)				
Interim replacement	1,84	1,68	1,61	1,50
Insurance	0,84	0,76	0,73	0,68
Operation and maintenance	2,35	2,27	2,18	2,11
Administration	0,91	0,89	0,85	0,82
Total Expenditure	61,64	56,35	54,10	50,37
P.V. of useable energy (GWh)	360,6	360,6	360,6	360,6
Effective cost of energy (¢/kWh)	17,1	15,6	15,0	14,0

As can be seen from the Tables below, the cost index, which is the weighted cost of energy presently being paid divided by the effective cost of the hydro energy, is less than 1,0 for each scheme, even when 80% of the construction cost is used. If the discount rate is varied from 6% p.a. to 10% p.a., the variation of the cost index, for the 80% construction cost is:

Alternative	Cost Index		
	i = 6% p.a.	i = 8% p.a.	i = 10% p.a.
1 - 10,4 MW	0,68	0,67	0,65
2 - 8,4 MW	0,74	0,73	0,72
3 - 6,9 MW	0,77	0,76	0,75
4 - 5,6 MW	0,83	0,82	0,80

If the full construction cost is used, then the variation of the cost index is:

Alternative	Cost Index		
	i = 6% p.a.	i = 8% p.a.	i = 10% p.a.
1 - 10,4 MW	0,55	0,54	0,53
2 - 8,4 MW	0,59	0,59	0,58
3 - 6,9 MW	0,63	0,62	0,60
4 - 5,6 MW	0,67	0,66	0,65

The economic viability of the hydro project would improve substantially if other electrical loads could be added which could utilize some or all of the surplus energy in a manner which would not exceed the capacity of the system (e.g., industrial load).

3.9 INITIAL ENVIRONMENTAL EVALUATION

3.9.1 Environmental Concerns

Environmental concerns over the Thelon river project at Baker Lake include fish passage, ice, navigation, the possible impact upon migrating caribou, and the possible Heritage River designation.

3.9.1.1 Fisheries

Fish species inhabiting Baker Lake and the Thelon river, between Schultz Lake and Baker Lake, include Arctic char, Arctic grayling, lake trout and round whitefish. The use made of the Thelon River by Baker Lake fish populations is unknown. However, it appears that round whitefish spawn upriver as an upstream migration has been observed in the fall. The importance of the Thelon river relative to other incoming streams, such as Kingyouuq creek and the Kazan river is also unknown. However, spawning runs up one or more of these streams by grayling or char is probable, as is the summer residence by grayling and possibly other species.

Domestic fishing, primarily for lake trout, occurs in the waters between the hamlet of Baker Lake and the outlet of the Thelon river, mostly during the open water season.

Placing a dam across the Thelon river would have two principal impacts with respect to fish production: blocking of fish migrations and the creation of a "lake" habitat above the dam.

Of these, the blocking of the fish migrations is potentially the greatest concern. Presently, it is impossible to determine the validity or magnitude of this concern since very little is known of the importance of the Thelon river to the maintenance of fish populations in Baker Lake. Specific information requirements include:

- the species of fish spawning in the Thelon River or inflowing waters;
- the fraction of Baker Lake populations which spawn in the Thelon River system;
- other locations, if any, which are also used;
- the locations where fish spawn, especially with respect to the location of the dam.

These studies to determine the above should be completed before the project proceeds to the stage of a full feasibility study. It is possible that these studies would conclude that fish passage facilities will need to be incorporated into the dam design, especially since a run of round whitefish has already been documented.

3.9.1.2 Ice

Considerable local concern exists over the impact of ice movements on the Thelon river during break-up. Ice thickness has been recorded to be nearly 3 m, and there is a local concern that ice from the lakes upstream will become blocked by the dam, or may take the dam out thus necessitating reconstruction. The community seemed quite keen on participating in the conduct of detailed ice studies.

3.9.1.3 Caribou

Unquestionably, caribou is the most important wildlife species to residents of Baker Lake. There are three herds of caribou which pass near the community: Kaminuriak, Beverly, and Wager Bay. The caribou harvest for 1982/83 was estimated at about 5 000. This accounts for approximately 96% of the total harvest by edible weight.

Concerns with respect to the caribou surround two issues, namely:

1) Transportation up the Thelon river to hunt caribou and the impact of the dam as an obstacle.

2) The impact on caribou migration as a result of the project.

Transportation

The rockfill dam required for the small hydro development will impede upstream and downstream travel by community residents and any other users of the river. The Thelon river is the route used by Baker Lake residents to access inland wildlife populations, especially the caribou.

The greatest volume of freighter canoe traffic occurs in July when there may be as many as 40 to 50 canoes travelling upstream in one day. At this time, the ice is not yet completely out of Baker Lake, but ice free conditions occur at the mouth of the Thelon river and in the area of Baker Lake near the community of Baker Lake. Concerns were expressed about costs associated with any delay at the dam to hunters, outfitters, and canoeists whilst awaiting their turn at the boat slide. A concern was also expressed as to whether or not a fee would be charged for transport over the dam, and inquiries pertaining to ownership and operation of the boat slide were made.

Caribou Migration

Concerns were expressed by Baker Lake residents over possible interference with caribou crossings of the Thelon river. Should the crossings of the three herds be pushed further from the community, then it would be more difficult and costly to secure their annual harvest.

Details of caribou movements across the Thelon river, including timing (especially in relation to ice break-up and freeze-up) and exact locations, should be determined from future studies in conjunction with the community, the Keewatin Wildlife Federation, and the Caribou Management Board. The loss of over 10 000 caribou in the James Bay project area in 1984 whilst attempting to cross the Caniapiscau river demands that precise knowledge of the movements of the caribou be known.

Heritage River Program

It is not known if significant numbers of tourist canoe parties make use of the Thelon river at the present time. However, its potential value as a canoe route is implied in that it has been given a very high priority for designation as a heritage river by the Parks Canada Heritage River Program.

3.9.2 Environmental Impacts and Mitigative Measures

3.9.2.1 Caribou

The impact of the Thelon hydro scheme on caribou migration is difficult to ascertain since there are no less than three different caribou herds in the area: Kaminuriak, Beverly and Wager Bay. Caribou studies are presently underway with the Keewatin Wildlife Federation and the Caribou Management Board and the results of these studies should shed some light on this matter.

Construction of the power project, transmission line and road over a period of years needs to be assessed with respect to their impact upon the movement of caribou herds in the area. Should the herds be significantly diverted from their present migratory routes as a result of the project, then this could result in lower and more costly harvests.

One of the effects of constructing the overflow dam is to raise the natural water level. In this case, it is about 10 m at the dam site decreasing to zero over a distance of about 10 kilometres upstream. Only if the present migration pattern of the caribou herds is within this area would the status quo be changed.

Mitigative Measures

Present studies by the Baker Lake Hunters and Trappers Association, Keewatin Wildlife Federation, and the Caribou Management Board are being funded at $200 000 to $300 000/year over five years.

3.9.2.2 Ice

The impact of ice break-up on the Thelon river and its effect on the proposed design of the hdro scheme would have to be investigated. Concern here lies in the possibility of the dam and powerhouse being designed to withstand the forces exerted by the ice during break-up.

Mitigative Measures

The effect of ice floes in the river has been considered by utilising an overflow dam with concrete armour plates. Also, the powerhouse has been located underground and away from any ice action.

Ice studies would be undertaken using community resources to establish firm design criteria for the power project. The cost of such studies would be about $100 000 per year over two years.

3.9.2.3 Fish Passage

A concern is that the dam may block upstream and downstream migrations of Baker Lake fish populations if they presently use the Thelon river system for spawning. Of particular concern to the Baker Lake community would be the relationship, if any, between the Thelon river and lake trout in Baker lake.

Mitigative Measures

In the absence of field data on the habits of fish populations in and around Baker Lake, a fish lock has been incorporated in the design of the overflow dam.

A field program would be required for a good assessment of project impacts and to provide data for fishway design (if required). It is recommended that such a program extend over two years to allow the tagging and enumeration of the various species. Costs could range from $200 000 to $300 000 over two years, depending on the findings of the first year's studies.

3.10 CONCLUSIONS

3.10.1 Project Viability

The project is capable of meeting the local demand, but the Thelon river is large and any attempt to harness its potential for the supply of a small amount of energy is difficult to justify. The main reasons contributing to the high cost of the project are:

- the fact that head has to created with a dam;
- the diversion floods are so large that the cost of the diversion works are very high.

As the economic analysis shows, there is no advantage in proceeding further with the Baker Lake Development, since the cost index never attains the value of 1,0, even with an 80% reduction of the construction cost.

3.10.2 Environmental Impact

Should the load forecasts improve significantly through regional industrial activity to make the project viable then major environmental studies will likely be needed with respect to caribou and fish migrations, and ice movement. The estimated cost of these environmental studies could range as high as $1,1 million.

SECTION 4 COPPERMINE

4.1 GENERAL

Since the Coppermine project was the only one to go to the final Phase of this Study, a special Annex Report has been prepared on it. However, for those readers who do not wish to examine the project in detail, that report is summarised in this section, without the loss of basic information.

Coppermine is an Inuit community of approximately 890 people and is the most northerly of the six communities. It is located at 67°-50'N latitude, 115°-05'W longitude on the northern coastline of the Canadian mainland, where the Coppermine River empties into Coronation Gulf. The community takes its name from the Hudson's Bay Company which sent explorers from Fort Prince of Wales to find the source of native copper brought to the fort - hence the name "Copper Inuit".

4.1.1 Population

The 1981 population of Coppermine, as recorded by Statistics Canada, was 809 of which 750 were Inuit. The Inuit form the predominant cultural group and there is an even balance between male and female. The largest age cohort groups were found between the ages of 0 and 24 in 1981. Recent statistics would suggest that the Coppermine population is growing at a rate of 3.1% p.a. It is therefore estimated that in 1984 there are 890 people living in Coppermine. The estimated number of people between the ages of 15 and 64 in Coppermine today is 530, split evenly between male and female.

4.1.2 Employment and Income

The economic base of Coppermine is largely traditional, although some members of the community have become involved with offshore exploration for oil and gas in the Beaufort Sea. Some members of the community also find employment at Echo Bay. Artic char, seals and caribou are harvested along with polar bear, musk-ox and small game. Tourism depends mostly upon the sale of arts and crafts, char fishing and the fact that Coppermine is the terminus of canoeing expeditions on the Coppermine River. Mineral potential of the area consists of gold, uranium, iron, zinc, lead, silver, cobalt, nickel and, of course, copper.

A rough estimate of present employment is given below:

Government (GNWT/Hamlet)	38
Oil and Gas	32
Mining	12
Retail	18
Utilities	2
Transportation	2
Service	6
Construction	14
Hunters/Trappers/Fishermen	
- Full time	5
- Part time (seasonal)	60
Total	189

With an estimated labour force of 375 people, the unemployment rate is roughly 50%. Per capita income in 1981 was recorded at $4 400 and consumer prices were 70%-80% higher than those in Edmonton (1983).

4.1.3 Housing

Housing is exclusively single family in nature. Many different repetitive housing designs have been used over the years with varying degrees of success. Some of the older houses are now being rehabilitated. In 1983 the NWT Housing Corporation maintained 168 single family units, GNWT 17 units, and the Federal Government 10. New units which are under construction in 1984 include singles and one structure with nine adjoining units. Heating is by means of fuel oil supplied by POL and the Co-op.

4.1.4 Commercial

Retail and wholesale trade is very limited with retail goods being supplied by the Bay and the Co-op. The Igloo Inn provides accommodation for 40 and also operates a dining room. Arts and crafts include articles made from caribou bone, copper artifacts, soapstone carvings and "Mother Hubbard" parkas.

4.1.5 Industrial

There are virtually no industries other than two small local contractors.

4.1.6 Recreation

The Coppermine Recreation Centre consists of a large hall with stage and an ice arena. The community also has a playground, school gym and a sports field.

4.1.7 Social Services

The community has a school which provides education from kindergarten to grade 9. The school had a 1983/84 enrollment of 226 students. The school year starts the 2nd week in August and ends the first week in June.

There is a four bed, one bassinet nursing station staffed by three nurses and a visiting doctor. Two people staff the community Social Services Office and there is a Coppermine Alcohol Committee. The Anglican, Pentecostal and Roman Catholic churches are also present.

A police force of 3 people is stationed in Coppermine along with Justices of the Peace and a coroner. Fire protection is provided by a 15 person volunteer fire brigade. Water is supplied by an 800 gallon fire truck. The fire alarm system consists of call boxes throughout the community and are connected to a siren.

4.1.8 Transportation

Coppermine has a 1 520 m gravel landing strip with runway lighting. The airport facilities include a small terminal building, rotating beacon, wind socks, a directional beacon and a fuel depot. The community is served by Northwest Territorial Airways which operates a scheduled air service between Coppermine and Yellowknife.

A float plane base, with no refueling services, exists along the waterfront. This base is usually used between mid-July and mid-September.

Barge service is available for community re-supply of bulk items such as fuel which originate out of Hay river.

Surface transportation is available through a taxi within the Community. There are no roads or highways external to the community.

4.1.9 Water, Sewer, Roads, Solid Waste

Water is drawn from the Coppermine river and chlorinated. Since the treatment excludes the use of settling tanks, the water supply contains sediments during the spring runoff. There is an intake and limited pipe distribution system. However, salt water intrusion into the intake has been a problem and the pipe distribution system is no longer in use. Water is truck delivered about 1-2 times per week.

Sanitation is provided mainly by a pump out truck which empties sewage holding tanks once or twice per week and disposes the contents at the solid waste area located between the airstrip and the Coronation Gulf. Some areas of the community, including the hotel, utilize bagged sewage. This waste is picked up daily and disposed in the solid waste area. Solid wastes are placed in steel barrels at the roadside and are picked up three times per week.

Gravel roads have been built in the community over the rocky terrain. Drainage is provided by means of open ditches and specially built swales which include vertical rip-rap to prevent sloughing due to melting of the permafrost.

4.1.10 Lifestyle

The lifestyle in the community may be described as Inuit traditional with a gradual change toward increasing wage employment and social assistance. Recent wage employment other than government has been provided by the non-renewable resource sectors of oil and gas and mining.

The importance of traditional pursuits in the community is highlighted in the tabulation below. These figures must be considered conservative since they are only based on approximately one year of data, one month being missing, and with only 50% of the hunters reporting.

Estimated Coppermine Harvest (1983)

Species	No.	Estimated Avg. Edible Weight (kg)/Species	Total Est. Edible Weight Available Each Year (kg)	%
Caribou	1 270	48	60 960	54
Seals	549	14	7 690	7
Char	8 531	2,5	21 330	19
Whitefish	5 188	2,8	14 530	13
Trout	1 756	2,4	4 210	4
Musk-Ox	18	110	1 980	2
Moose	7	199	1 390	1
Wolves	49	-	-	-
Wolverine	64	-	-	-
Arctic Hares	89	2,3	200	-
Ptarmigan	477	0,4	190	-
Ducks	562	0,7	390	-
Geese	191	2,4	460	-
		Total	113 330	100

Source: GNWT - Renewable Resources

Note: Reporting rate - 50%

To replace the total amount (113 300 kg) of meat/fish with say beef at $10/kg would represent 1.1 million dollars annually or $5 600 per household. In percentage terms, this shows that the migrating fish of char and whitefish account for about one-third of the total diet. The domestic fishery could therefore represent one-third or $1 900/household.

Quite apart from the economics, fishing is an important way of life to the Inuit. The domestic fishery provides the occasion to move the family out of the community to summer residences located between the estuary and Bloody Falls; residences consist of both wood cabins and tents. Transportation between these summer residences and the community is by means of boat.

Trapping is one of the traditional ways of life of the Inuit, and the value of fur harvested for the year 1982/83 was estimated at $67 700.

4.2 EXISTING ENERGY LOADS

4.2.1 Electric

The existing electrical load in 1982/83 amounted to 2 593 MWh with a peak load of 580 kW and a load factor of 51%. Sales amounted to 2 330 MWh with the domestic market contributing 53%, commercial 46% and street lights accounting for the remainder. There were no wholesale or industrial sales. Average annual growth over the past 6 years has amounted to 6,5%.

4.2.2 Heating

Space heating in Coppermine is supplied by oil furnaces and in 1983/84, 329,200 gallons of heating oil were consumed in Coppermine. This is equivalent to approximately 9 500 MWh of heat as an electrical load. On the basis of sales, this heating load is roughly 4,1 times the electrical load.

4.3 LOAD FORECASTS

The load forecast for Coppermine was prepared in a similar fashion to that employed for Baker Lake. Hence, the methodology and assumptions are not repeated but those factors which are unique to Coppermine are stated below:

- Annual electrical load factors for Coppermine averaged 0,52
- Lifestyle assumptions as:
  - 6,5% annual growth in domestic consumption to a maximum of 2 600 kWh/capita; then 4,0% to 3 000 kWh/capita; then 2,0% thereafter;
  - 3,0% annual growth in commercial/institutional consumption to 1994; 2,0% thereafter.
- Population forecast at a natural growth rate of 3,1% as given in Table 4.1.

TABLE 4.1

POPULATION FORECAST - COPPERMINE

Year	Population
1982	836
1983	861
1984	887
1985	914
1986	942
1987	970
1988	999
1989	1 029
1990	1 060
1991	1 092
1992	1 125
1993	1 159
1994	1 194

Computer rounding has occurred.

4.3.1 Energy and Capacity

The average annual energy which must be generated over 40 years has been calculated for five scenarios. These average energy values and the corresponding design capacities are given in Table 4.2 and shown in Figure 4.1.

Table 4.2 indicates that the design capacities vary from about 0,66 MW for the low electrical load scenario in 1984 to about 12,8 MW for the high combined load in 2029. Figure 4.1 also demonstrates that conservation, especially for heating, is desirable and more important than increases in the electric load due to improved lifestyle. However, for the medium combined load, which has been used as the hydro plant design criterion, the useable plant capacity varies from about 5 MW in 1984 to about 10,3 MW at the end of the economic life of the project in 2029.

4.3.2 Load Shape

The average monthly load requirements in 1994 for the three combined load scenarios are shown in Figure 4.2. Table 4.3 provides the details of the monthly load variation for the medium combined load scenario in selected years. The load shapes depicted in Figure 4.2 show relatively high loads in March and April, when the river flow is low, and low loads from June to August, when the river flow is high.

TABLE 4.2

LOAD FORECAST - COPPERMINE

	Low Electrical Load		Base Electric Load		Low Combined Load		Medium Combined Load		High Combined Load	
Year	Gen (GWh)	Design (MW)	Gen (GWh)	Design (MW)	Gen (GWh)	Design (MW)	Gen (GWh)	Design (MW)	Gen (GWh)	Design (MW)
1984	2,901	0,66	2,901	0,66	16,415	4,59	16,561	4,62	16,561	4,62
1989	3,026	0,69	3,363	0,76	17,127	4,79	17,641	4,91	19,544	5,44
1994	3,118	0,71	3,898	0,89	17,648	4,94	18,505	5,13	22,918	6,37
1999	3,443	0,78	4,304	0,98	19,485	5,45	20,432	5,67	25,303	7,03
2004	3,802	0,86	4,752	1,08	21,513	6,02	22,558	6,26	27,937	7,76
2009	4,197	0,95	5,247	1,19	23,752	6,64	24,906	6,91	30,844	8,57
2014	4,634	1,05	5,793	1,32	26,225	7,34	27,498	7,63	34,055	9,46
2019	5,117	1,16	6,396	1,46	28,954	8,10	30,360	8,42	37,599	10,45
2024	5,649	1,28	7,061	1,61	31,968	8,94	33,520	9,30	41,513	11,53

TABLE 4.3

COPPERMINE

Average Monthly Loads (MWh)

Medium Combined Load

	1994			2009			2024		
Month	Electric	Heating	Total	Electric	Heating	Total	Electric	Heating	Total
Jan	421	2 019	2 440	567	2 718	3 285	763	3 658	4 421
Feb	366	1 859	2 225	492	2 503	2 995	662	3 368	4 030
Mar	382	1 888	2 270	513	2 542	3 055	691	3 421	4 112
Apr	326	1 438	1 764	438	1 936	2 374	590	2 605	3 195
May	270	973	1 243	363	1 310	1 673	489	1 763	2 252
Jun	242	581	823	326	782	1 108	439	1 052	1 491
Jul	242	348	590	326	469	795	439	631	1 070
Aug	278	392	670	374	528	902	504	710	1 214
Sept	294	624	918	395	841	1 236	532	1 131	1 663
Oct	338	1 031	1 369	454	1 388	1 842	612	1 868	2 480
Nov	390	1 525	1 915	524	2 053	2 577	705	2 763	3 468
Dec	425	1 845	2 270	572	2 484	3 056	770	3 342	4 112
Total	3 980	14 530	18 510	5 350	19 560	24 910	7 200	26 320	33 520

Note: Rounding has occurred.

4.4 POTENTIAL SITES

The most suitable site, which had been suggested in previous studies, is located at Bloody Falls, on the Coppermine river about 16 km upstream of the community, Figure 4.3. This is the closest site to the community. Bloody Falls has a natural head of about 6 m, and possesses suitable geotechnical foundation conditions.

A site at Escape Rapids was also investigated but was ruled out as inferior to the Bloody Falls site. This was due to its remoteness and much reduced natural head.

A site on the Kendall river near Dismal Lakes was also examined and ruled out for two reasons:

- the very long transmission distance from the site to Coppermine
- the fact that the river froze to the bottom in winter.

4.4.1 Hydrology

The estimate of flows in the Coppermine river at Bloody Falls was done using the methodology of section 2.5. However, additional information was available at Bloody Falls since Water Survey of Canada erected a streamgauge just upstream of the falls in July 1983.

Correlation was sought between the older gauge at the outlet of Point Lake in the upper reach of the Coppermine river, and the Bloody Falls gauge. But none was found for the following reasons:

- the Bloody Falls record was too short
- the flow out of Point Lake is regulated
- there are many lake systems between Point Lake and Bloody Falls

Consequently, the estimation of minimum flows at Bloody Falls was done on a regional basis. It was assumed that the minimum flow at Bloody Falls had two components, one from Point Lake and the other from Takijuq Lake. It was assumed that the other river tributary systems froze to the bottom in winter.

Using the regional approach, the specific yield for the Coppermine drainage basin at Bloody Falls was taken as 4,75 $l/s/km^2$ over 40,404 km^2. The resulting average flow of 191,9 m^3/s was multiplied by 0,31, the ratio of minimum flow to average flow in the Thelon river, to give a minimum flow of 59,5 m^3/s at Bloody Falls.

Using a specific yield of 5,21 $l/s/km^2$ for the Takijuq drainage basin of 6 800 km^2, then an average flow of 35,43 m^3/s is obtained. It was then ascertained that Takijuq Lake covered 35% of the contributing drainage area, and hence, from Figure 2.6, the ratio of minimum to average flow was 0,6. If this factor is applied to the average flow from Takijuq Lake, then a minimum flow of 21,2 m^3/s is obtained.

It is known from the Point Lake records that the minimum flow out of Point Lake is 36,8 m^3/s. Hence it could reasonably be expected that:

$$\text{minimum flow at Bloody Falls} = 36{,}8 + 21{,}2 = 58{,}0\ m^3/s$$

This value compares reasonably well with 59,52 m^3/s obtained earlier, and hence for the design of the project, the flow of 58 m^3/s was adopted. The graph of average flow at Bloody Falls was constructed using this minimum flow of 58 m^3/s and Figure 2.6. The resulting hydrograph is shown on Figure 4.4 and the corresponding flow duration curve on Figure 4.5.

To date five flows have been measured at Bloody Falls and are compared with those at Point Lake.

Date	Flows - m^3/s Bloody Falls	 Point Lake
1983		
19 July	707	231
5 August	494	260
9 September	1 006	232
1984		
26 March	105	48 to 60
10 August	686	336

* Estimated from the recession curve of average flow conditions at Point Lake.

This data along with measured sections of the river allowed two provisional rating curves to be prepared; one for upstream of the falls, in the area of the intake, and the other downstream of the falls, in the area of the tailrace. These curves are shown on Figure 4.6.

The flood flows which could be expected at the Bloody Falls site were calculated by the regional technique given in Section 2.5, and Figure 4.7 is a graphical representation of these calculations.

4.5 GEOTECHNICAL

4.5.1 General

The terrain at the proposed project site is illustrated on the mosaic, Map 2. This mosaic has been terrain-typed in accord with the accompanying legend and shows a wide range of terrain units from Precambrian igneous rock to actively forming delta and alluvial deposits.

At Bloody Falls the Coppermine River is constricted by outcrops of gabbro to form a small lake or reach of comparatively low slope just upstream of the falls. The river is presently forming a delta at the head of this lake (photo 5).

Near surface materials in the vicinity of Bloody Falls and to the north are generally level, flat lying marine plain, deltaic and alluvial deposits. This material, which is 3 m to 5+ m in thickness, overlies igneous and metasedimentary rock. Exposures along the river banks below the falls confirm that the material is predominantly silt and sand which tends, for the most part, not to be ice rich in exposures. It is therefore stable at comparatively steep slopes. The exception is the reach immediately downstream of the falls along the left bank and along the left bank tributary streams, which exhibit widespread erosion and mass movements commonly associated with thawing, ice rich slopes in silt.

As illustrated on Map 2, the upland west of the proposed reservoir is predominantly a thick plain of marine sand and silt. Along the left bank of the river, upstream of the falls, significant segments of the potential reservoir slopes are now at a shallow and stable angle. Along the right bank is an eroded blanket of fine grained colluvium and some alluvial deposits. The falls are constricted by outcrops of deeply jointed overlying metasedimentary rock (photo 7).

Immediately upstream of the falls, in the area of the intake, it is anticipated that there is metasedimentary rock which outcrops at river level on each bank and dips slightly to the northwest. Within the channel this bedrock is likely covered with a veneer of granular material. The abutments are shallow sloping colluvium which is partially armoured to a height of about 8 m above river level. Above this level the shallow slopes continue with a blanket of vegetated marine material and fine grained colluvium over bedrock. It is evident that stable foundation conditions are present for a structure at this location.

As is evident from [illegible] mosaic and the field photos, the river banks immed[illegible]ream of the intake site are in thick marine sand[illegible] which are stable at very steep angles (photo 8). In some sections, these materials have eroded along slopes and have formed colluvium which lies at shallow angles. It is expected that the sandstone slopes will not suffer more than minor sluffing during flood time. Since the river banks in the colluvium are now resting at shallow angles, they are not susceptible to further significant movements. As noted earlier, the lower 8 m are largely, stable armoured beaches.

4.5.2 Powerhouse

Excellent foundation conditions appear to be in place at the proposed location of the powerhouse (photo 12).

4.5.3 Tunnel

The proposed diversion and power tunnel will be excavated through the rock of the left bank from an intake located in or near the metamorphosed siltstone outcrop (photo 7) to the gabbro outcrop near the bottom of the falls (photo 12). The tunnel will be therefore drilled through the highly jointed igneous rock which forms the river banks at the falls. It is possible that this rock will require some structural support, such as rock bolting, to ensure integrity of the tunnel and some form of lining to eliminate seepage; the perched lake (photo 6) lies along the tunnel alignment. On the other hand low ground temperatures (-7°C) may prevent significant leakage. During the field trip in August, surface water was ponded at several points above the rock despite a very thin veneer of tundra. For the prefeasibility study a full concrete lining should be assumed. If the study of the scheme proceeds to feasibility stage several test holes should be drilled along the proposed tunnel line to determine the integrity of the bedrock, as well as the distribution and temperature of the ground ice.

4.5.4 Borrow Sources

The primary source of granular borrow will probably be the terraced esker, immediately downstream of Bloody Falls along the left bank, which may yield an estimated 400 000 m^3 of material. Alternatively, the alluvial terrace on the left bank, 4 km upstream of the falls is a potential source of granular construction material. The terrace must be sampled to confirm grain size distribution, but it would appear to be a good source of sand, gravel and cobbles with a potential volume of about 14×10^6 cubic metres. This terrace will become submerged as a result of the project. There are several similar terraces further upstream.

An alternative source of granular material exists in the form of several eskers located 21 km to the east. Exposures of these eskers indicate a good distribution of grain sizes from sand to boulders, and it is expected that the total volume of such material available from this source exceeds 6×10^6 cubic metres.

All of the other construction materials which are likely necessary, ranging from sandy silt to very large angular rock fragments suitable for rip rap, are available within close proximity (approximately 1 km) of the proposed dam site. The silt would come from marine deposits (photo 11) and the rock from talus and outcrops (photo 9) and tunnel excavation.

4.5.5 Transmission Line Route

Most of the terrain between Bloody Falls and Coppermine is a sandy alluvial delta or sandy marine plain with thermokarst features (Map 2). The surface is level and, exposures along the river bank suggest that the material is not ice-rich, at least along the lower reaches. The terrain is therefore generally stable. Widespread erosion and mass-wasting of thawing slopes is limited to the left bank for a distance of about 2 km downstream of Bloody Falls. These failures extend about 1 km from the river bank and along the tributary ravines. Final routing of a stable transmission line supported by timber poles driven into prethawed pilot holes should not present a problem.

4.6 PRELIMINARY DESIGN

During the first phase of the study, three possible sites for developing a hydroelectric plant for Coppermine were examined were examined using 1:250 000 scale topographic maps. The sites were:

- Kendall river near Dismal Lakes;
- Escape rapids, Coppermine river;
- Bloody Falls, Coppermine river;

The first two sites were ruled out because of considerations of the magnitude of the load, the length of the transmission lie which would be required and the available head. In addition, the Kendall river froze to the bottom during the winter.

The Bloody Falls site was initially examined with the objective of providing enough energy to satisfy both the normal electric load and the heating load. Development of this site, with this objective in mind, required the construction of an overflow, rockfill dam just upstream of the falls, a diversion/power tunnel and powerhouse.

The development of the site was found to be feasible, and hence field investigations were carried out at the site in the second phase of the study. The field work allowed the measurement of the available head and a better evaluation of both the river flows and the geotechncial aspects of the site. Based on the survey data, new maps, using existing photographs, were prepared at a scale of 1:2 500.

The study in the second phase showed that cost of the diversion tunnel, which eventually became the power tunnel, was substantial. Also, there were environmental concerns about fish - principally artic char, which is an important aspect of this project. These doubts arose out of insufficient information of the fish life in the Coppermine river.

In the second phase, the cost effectiveness of four schemes varying from 5,2 MW to 9,6 MW with investment costs varying from $35 million to $52,2 million, respectively, showed that perhaps the smallest scheme could be viable if the discount rate was taken as 6% p.a. The cost for satisfying the heat load was apparently making the project uneconomic. It was decided therefore to re-examine the site to supply only the normal electric load and to assume that excess energy could be regarded as being utilised for heating. It was also decided to develop the scheme without a dam across the river and so obviate environmental problems concerning the movement of fish in the river.

Field measurements indicated that the gross head at Bloody Falls was 6,33 m when the flow was about 700 m^3/s. As the provisional rating curves, Figure 4.6, show this head decreases as the flow decreases. At the minimum flow of 58 m^3/s the gross head is estimated to be about 5,5 m.

Since the objective of constructing the hydro plant was to replace fuel - diesel and heating oil - then the energy output from the plant should, as far as possible, be firm. Using the predicted flows, four schemes were examined with flows of 24 m^3/s, 46 m^3/s, 56 m^3/s and 70 m^3/s.

Since no dam was to be used for the development of the site, it was proposed that a diversion trough be excavated in the river bed from the normal river channel, near the right bank of the river, to the intake situated on the left bank. The exact configuration of the trough and sediment removal works can only be determined by a hydraulic model, which would appropriately form part of a future Feasibility Study. From the intake a tunnel would take the diverted river flow to the powerhouse and eventually back to the river below the falls, Figure 4.8.

The diversion trough slopes towards the intake becoming deeper as it approaches the intake, and is shaped so that the upstream slope is flatter than the downstream one. Except for the largest turbine flow which was investigated, namely 70 m^3/s, there will always be some flow passing down the falls.

The operating requirement of the turbine demands a very large upstream surge chamber because the available head is small and the flow is large. To satisfy this requirement, the powerhouse was located just downstream of the two perched lakes, Photo 6, which together act as a headpond. The two lakes would be joined together by excavating a canal which is more than 2,5 m deep to prevent freezing to the bottom, and they are connected to the tunnel by a shaft of the same diameter as that of the tunnel. Figure 4.9 shows the developed profile of the project.

The powerhouse is a deep semi-underground structure and only a small portion of it is above ground. The tailrace tunnel, which has been designed to carry stop logs at the exit, is under pressure and thus requires a downstream surge shaft.

The hydraulic calculations were oriented towards obtaining a minimum net head of 4 m; friction losses in the tunnel forming the major component of the total head loss. Hydraulic calculations were also made to determine the diameter of the downstream surge shaft and the variation of the water level in it during load acceptance and load rejection.

The blocky nature of the exposed rock at the site together with the unknown competence of the metamorphosed siltstone made it necessary to assume, conservatively, that the rock through which the tunnel will be driven will be highly jointed in places. A thin shotcrete lining, no more than 50mm, over the entire perimeter may suffice for structural support. However permeability is also important. It is presently assumed that the rock is frozen and that concrete lining may not be required. However, after the plant is in operation a new permafrost equilibrium line will be established in the area and a seepage barrier may not be maintained. For this reason a concrete lining has been assumed to be required for prefeasibility cost estimates.

It was assumed that the existing diesel generators would be maintained and kept as reserve, hence only one turbine and generator was allowed for in the powerhouse. For the required flow and range of head conditions which would occur, the only suitable turbine was the Kaplan. The size of the tunnel is quite large and, again, to reduce costs there is no valve in the penstock immediately upstream of the turbine. To isolate the various parts of the system, the gates and stop-logs must be put in place and the entire water conveyance system pumped out. Since the diesel units act as back up, time is not critical in emptying the system.

The synchronous generator, operating at 0,85 lagging power factor, is directly coupled to the turbine. It was assumed that a step-up transformer was placed between the generator at 4.16 kV and the transmission line, 12 kV. Similarly, standard switchgear equipment and a step-down transformer at the end of the transmission line were assumed.

The operation of the hydro plant could be either remote controlled or automatic. Telecommunication between the existing diesel station and Bloody Falls would be provided by telephone cable attached to the powerline poles. The telephone cable would also serve to operate the intake gate in the event of a malfunction of the plant.

The construction schedule for the project is shown on Figure 4.10.

4.7 Power and Energy

The plant flow of the selected scheme is less the minimum flow in the river and hence the firm energy production is therefore equal to the average energy.

The rated output at the generator terminal was found by using the formula:

$P = 8\ Q\ H_n$ (kW)

where,

Q = flow in m3/s
Hn = net head in m.

In the above formula, the combined efficiency of the turbine and generator was assumed to be 82%. In calculating the energy, a factor of 0,95 was applied to allow for occasions when all of the available water would not be used.

The rated output and energy from the plant, based on the electrical characteristic of the transmission line, are as follows:

Rated power	1 888 kW
Average energy	15,7 GWh p.a.

Based on the foregoing discussions, the characteristics of the four schemes which were examined are as follows:

Item	Unit	Schemes			
		1	2	3	4
Head					
- gross	m	5,5	5,7	5,65	5,7
- net	m	4,78	5,06	4,98	4,97
Flow	m^3/s	24,0	46,0	56,0	70,0
Diversion trough					
- bottom width	m	4,0	6,0	7,0	8,0
- invert at left bank	m	1,50	0,90	0,70	0,40
Intake structure					
- top elevation	m	20,0	20,0	20,	20,0
- gate sill elevation	m	-3,0	-4,50	-5,00	-6,00
- width of intake	m	11,00	12,50	13,00	13,50
- trashrack					
- number	-	2	2	2	2
- width (each)	m	3,00	3,75	4,00	4,25
- height	m	5,70	7,00	7,50	8,00
- gates		Data as for trashrack			
Tunnel					
- headrace	m	514	514	514	514
- tailrace	m	200	200	200	200
- diameter	m	3,85	5,40	5,79	6,60
Powerhouse					
- number of units	-	1	1	1	1
- turbine type		KAPLAN			
- rotational speed	r.p.m.	180,0	128,6	120,0	105,9
- output	kW	922	1888	2243	2800
Surge shaft					
- length	m	11,0	11,0	11,0	11,0
- diameter	m	4,5	7,0	7,6	8,5
- upsurge	m	4,68	4,97	5,19	5,19
Canal					
- length	m	25	25	25	25
- depth	m	5	5	5	5

4.8 INITIAL ENVIRONMENTAL EVALUATION

4.8.1 Environmental Concerns

Environmental concerns over the project in Coppermine mainly surround the fishery on the Coppermine river. Species in the river include arctic char, whitefish and trout. Other concerns relate to the aesthetic appearance of the falls and the existing canoe portage.

4.8.1.1 Fisheries

The Coppermine river fish populations are virtually undescribed. A recent paper by staff of the Freshwater Fish Institute in Winnipeg (Gillman and Christopherson, 1984) examines age, length and weight of char caught in 1981, but this represents the only known published data. All other information is based on the knowledge of Coppermine residents.

Arctic Char

Relatively little is known about the complete life cycle of the char which inhabit the Coppermine river system and estuary. Local knowledge suggests the following migration cycle:

Char Run	Cohort	Migration Period
Incoming	"Pale Char" (larger)	August - early September
Incoming	"Colour Char" (smaller)	mid to late September
Outgoing	?	October/November
Outgoing	?	June/July

The commercial quota has been set at a mere 223 kg/year. Domestic harvests from the Coppermine river have been reported to have ranged from 6 700 to 67 000 kg/year. These harvests of char are taken mainly between Bloody Falls and Coppermine. The largest catches are obtained with nets in both open water and under the ice. Rod and reel catches are also quite common on the downstream side of the falls. Numerous cabins and tents are erected on the banks of the Coppermine river to accommodate the fishermen and their extended families during the summer.

Char is processed by filleting and air-drying and is used as a "snack". Other portions of the catch are frozen in private or community freezers. Recent harvest statistics suggest 8 530 char for 1983 or 22 860 kg.

Arctic char is primarily an anadromous species (spends part of its life in the ocean but returns to fresh water for spawning), although isolated non-migratory populations occur in lakes. Anadromous populations occur primarily around the Arctic Ocean, but also along the coasts of the northern half of Hudson's Bay, Labrador, north-east Newfoundland, western Alaska and all of Greenland and Iceland. This distribution generally corresponds to the distribution of sea-ice in winter (ref. 2).

Generally, in the central Canadian Arctic, char spawn in lakes because the rivers freeze completely in winter (ref. 2). Whether or not this is true of the Coppermine river population is unknown. The usual pattern of migration is as follows:

- mid-August to September - char enter fresh water to spawn
- char overwinter in fresh water
- char descend rivers to salt water during ice break-up
- char spend 1-3 months feeding in coastal waters before returning to fresh water.

Char generally spend the first 3-5 years of life entirely in fresh water before making the first seaward migration. Larger fish generally commence migrations in advance of smaller immature fish. Only a portion of the mature fish returning to fresh water will spawn in a particular year.

Char have been observed to ascend Bloody Falls and proceed further upstream.

Whitefish

The other known migrating species in the Coppermine river are whitefish. As with the char, the migration, spawning and other habits of this fish in the Coppermine river system is relatively unknown. The last reported catch was 5 188 for 1983 based upon a reporting rate of 50%.

Virtually nothing specific is known about the populations of other fish species which use the Coppermine river; these include broad whitefish, round whitefish, lake trout and probably arctic grayling. However, it is probable that all of these species overwinter in deeper lakes and river reaches, which may require them to migrate to upstream of Bloody Falls. All of these species spawn in fresh water although some species, e.g., whitefish, may feed in coastal waters during parts of the year.

Summary

The obvious concern with respect to fisheries is the continued passage of migrating fish through Bloody Falls into the upper reaches of the Coppermine watershed and to allow for their return to the estuary.

4.8.1.2 Wildlife

Seals and caribou appear to be the most important wildlife species which form a part of the diet of the Inuit at Coppermine, but other animals, including polar bear, musk-ox, small game and possibly other marine mammals, are also used. It appears that these populations would be unaffected by the project, but this should be confirmed by further discussion with local wildlife hunters if the project proceeds beyond the present stage.

4.8.1.3 Aesthetics

Bloody Falls is an impressive site from an aesthetical point of view. The narrowed river within a rock canyon with a drop of 6.3 metres over 1 000 metres allows the formation of a series of standing waves from the top to the foot of the falls. These standing waves and the swift currents and eddies present an awesome display of water power.

The falls are enjoyed by local residents of Coppermine, fishermen, tourists and canoe trippers. There would be a concern from all these groups of people should the aesthetics be significantly affected by the proposed power project.

4.8.1.4 Canoe Portage

The existing trail along the west bank of the falls provides a means for canoe trippers to portage around the falls. Therefore any changes to this trail would have to be mitigated through the provision of an alternative portage alignment. The steepness of the present trail in some areas perhaps offers an opportunity for a better route.

4.8.2 Environmental Impacts and Mitigative Measures

4.8.2.1 Fish Passage

Impact

The maintenance of the population of arctic char and likely several other species in the Coppermine river depends on unobstructed passage upstream and downstream through Bloody Falls. Prevention of this passage would seriously jeopardize these populations and cause severe hardships for the community.

Even though no dam is proposed, it will be necessary to understand the fish migration cycles and characteristics to ensure that enough water is flowing over the falls at critical migratory times of the year to ensure safe passage of fish. With a hybrid hydro/diesel system any necessary reduction of hydro power can be made up by the diesel units over short periods of time.

Mitigative Measures

To provide baseline information for use in determining operating practices, a detailed field program is required. The basis of the program would be a counting fence(s) operated in two consecutive years. Fish ascending and descending the rapids would be enumerated by species and size and tagged and samples would be taken for more detailed analysis (age, length, weight, sexual development).

Based on a field program lasting two years, making considerable use of local assistance, the costs of the required fisheries studies, including laboratory work and reporting, are likely to be in the order of $300 000.

4.8.2.2 Aesthetics

Impact

The hydro scheme is designed as a run-of-the river development. Due to the flow characteristics of the river and the pattern of the forecasted load, over 90% of the flow during the summer will be spilled, thereby not visibly altering the downstream aesthetics of the present rapids.

Mitigation

As mentioned above, the appearance of the natural falls during the summer months will be visibly unaltered. This is due to the manner in which the hydro scheme is designed to meet the small electric load. The reasons are:

- no dam is required;
- in summer, due to the reduced total load, the turbine flow is less than the rated station flow of 46 m3/s, and the impact of this small depletion on the natural river flow across the falls is not discernible to the human eye;

During the winter the appearance of the falls should be little different from its natural appearance.

4.9 PROJECT EVALUATION

4.9.1 Cost Estimates

Cost estimates were prepared for four schemes by applying unit costs, which were assumed to reflect the local conditions, to specific quantities. Some of the quantities have been based on the available topographic maps, and there is, therefore, an inherent error. The costs which have been supplied must be considered as order of magnitude values with an error of about ± 20%. The following additional guidelines were used in preparing the costs:

- the accesses were properly constructed roads;
- a three year construction period was assumed interest during construction was calculated at an 8% discount rate;
- no costs resulting from any environmental requirements were taken into account as these are minimal, if any.

The investment costs for the selected scheme is given in Table 4.4, which clearly shows that about 70% of civil works cost are taken up by the tunnel and the powerhouse. Also, the cost of the turbine and generator form about 50% of the cost of the generating equipment.

The estimated peak labour for the selected scheme is about 165 of which about one third would be recruited locally. Also the estimated disbursements in the community is about $1,5 million.

4.9.2 Economic Evaluation

4.9.2.1 General

The economic evaluation of the project was done with the following objectives in mind:

- determination of the optimum hydro plant size, i.e., the plant size which yield the maximum net benefit;
- calculation of the net benefits of the project;
- determination of the most suitable year in which to commission the optimum size hydro plant;
- determination of the period which is needed to recover the initial investment.

TABLE 4.4
COPPERMINE DEVELOPMENT
COST ESTIMATE (1984 dollars)
1888 kW

Item	Costs - $ x 10^6	
Civil Works		
Access	0,605	
Cofferdams	0,390	
Intercepting trough	0,270	
Intake	0,806	
Tunnel and surge shaft	4,038	
Canal	0,053	
Powerhouse	2,219	
Tailrace	0,086	
Sub-total		8,467
Electrical and Mechanical		
Turbine	0,900	
Generator	0,515	
Miscellaneous equipment		
Electrical	0,333	
Mechanical	0,361	
Intake Equipment	0,406	
Outlet equipment	0,180	
Transmission line	0,860	
Sub-total		3,555
Indirect construction costs (15% of civil works)		1,270
Engineering and management (10%)		1,329
Sub-total		14,621
Contingencies (10%)		1,462
Construction cost		16,083
Interest during construction (8%)		1,804
Capital cost		17,887
Cost/kW	$9 474	

Notes:
1) Estimated capital costs are ± 20% accuracy
2) Does not include costs for feasibility and environmental studies

These present worth analyses were done using discount rates of 6%, 8% and 10%. Also, sensitivity tests were carried out by varying the construction cost and the cost of fuel. The program also took into account the hydro energy which could not be used for heating, for example in the summer when both the temperature and river flows are relatively high.

The computer program basically compared two generating systems to meet the projected load over a 40 year period, and compared their capital and operating costs. The two systems were made to provide a given reliability, in this case a loss of supply of 15 hours per year. The two systems were:

- a diesel generating plant, in which the machines were retired after a service life of 20 years and replaced by new ones;
- a hydro-diesel system, in which the hydro plant was assumed to have an economic life of 40 years, and the diesel units, serving as a back up and run nominally, were replaced using the same criterion for the diesel generating plant system.

In preparing the diesel and the hydro-diesel systems, the computer model also allowed for the following:

- the hydro plant, which produced firm energy, was used preferentially, or stacked first, and the balance of the load was met by diesel unit. The diesel units were stacked or ordered according to their variable fuel and operating costs;
- separate heat rates were applied to each existing and new diesel unit, and annual fuel costs were calculated on the basis of the number of hours of operation and total energy generation assigned to each diesel unit;
- operation, maintenance, administration, interim replacement and insurance charges were taken into account;
- transmission costs, not common to the two systems, were allowed for.

Since the analysis produced a benefit-cost ratio and internal rate of return, the following definitions are necessary.

Definition of Costs

The cost streams are composed of capital costs, fuel costs, insurance costs, operating and maintenance costs, and replacement costs. Costs which have already been spent or are already irrevocably committed (sunk costs) and some costs such as transfer payments (in particular, taxes) were ignored in the appraisal.

Definition of Project Benefits

The project benefits are based upon the avoided costs (capacity and energy costs) resulting from the project implementation.

As the project is part of an integrated system, the benefits are estimated by comparing total system costs with and without the project, with the benefits being equal to the difference between the total costs of the two cases without assigning any cost to the project. The difference in total costs, after including the discounted costs of the project, and after adjusting for the heating credit, will be the net present value of the project.

The heating credit was obtained as the present worth of electrical heat supply benefits (i.e., avoided oil costs) less the corresponding costs of heating unit conversions.

The net benefits for the hydro project were defined in terms of the present worth of system capital and operating costs as

Benefits = Reference (all diesel) plan cost
less costs for the alternative plan with the hydro project
plus net benefits from displacing oil heating.

Internal Rate of Return

The basic criterion suggested to measure the economic viability of the project is the internal rate of return (IRR). This is the discount rate at which the discounted stream of benefits is equal to the discounted stream of costs. This criterion is convenient as the derived breakeven rate of return may be compared directly to a 'decision' discount rate.

Benefit Cost Comparisons

For a single project considered as part of a system plan the benefit cost ratio for the given project can be represented by the benefit cost ratio as follows:

$$\text{Benefits/Costs} = \frac{\text{Net Benefit due to the Project + PW of project costs}}{\text{PW of project costs}}$$

Plant Optimization

The optimal plant installation is such that the last increment of costs is equal to the increment in the benefits. The optimum is reached when the marginal costs are equal to the marginal benefits, i.e., when the marginal B/C ratio is equal to one.

4.9.2.2 System Load

For the projected load forecasts which were analysed, the computer model, in effect, produced a cash flow of capital and operation costs for the two systems. These costs were then present valued to January 1984 at the interest rates referred to; by so doing the two cost streams of expenditures became comparable. It was initially assumed that the earliest on power date of the hydro plant was 1990, so that a load period of 1990 to 2029 was examined. However, the preferred on power date for the selected scheme was obtained from the computer analysis.

The development of the load forecast is described in Section 2. The analysis have resulted in two forecasts for the electrical and the combined electrical plus heating load

- Median or base case
- low forecast

These forecast demands are shown in Figures 4.10 and 4.11. The optimization studies have been based on the base case forecast, and the low forecast was used in the sensitivity tests applied to the preferred scheme.

Representative forecast demands are as follows

BASE CASE FORECAST LOADS

	Electrical Load		Combined Electrical and Heating	
	Peak kW	Energy GWh	Peak kW	Energy GWh
1985	679	2,99	4 677	16,77
1990	784	3,46	4 953	17,811
2000	1 000	4,38	5 783	20,841
2010	1 214	5,32	7 048	25,404
2029	1 778	7,79	10 268	37 009

LOW FORECAST LOADS

	Electrical Load		Combined Electrical and Heating	
	Peak kW	Energy GWh	Peak kW	Energy GWh
1985	666	2,93	4 630	16,56
1990	694	3,04	4 820	17,23
2000	796	3,51	5 560	19,87
2010	969	4,28	6 773	24,23
2029	1 413	6,24	9 871	35,30

4.9.2.3 Generating Systems

The existing diesel system at Coppermine is as follows:

Engine Make and Model	Capacity Actual kW	Name plate kW	Year Installed
Mirrlees EV6	200	225	1967
Mirrlees EV6	200	225	1967
Mirrlees EV6	200	225	1967
Mirrlees EV6	375	400	1973
Cat D398	600	600	1976

Using the criteria which have been outlined above, the two generating systems which wre produced by the computer model are given below. The addition of new diesel units were sized at 600 kW to maintain compatibility with the size of the load and the trend in the size of existing diesel plant.

All Diesel Plan

Year	Retirement kW	Additions kW	Installed Capacity kW
1984			1 675
1987	3 x 225	2 x 600	2 2 00
1992		1 x 600	2 800
1993	1 x 400		2 400
1996	1 x 600	1 x 600	2 400
1999		1 x 600	3 000
2007	2 x 600	2 x 600	3 000
2012	1 x 600	1 x 600	3 000
2016	1 x 600	1 x 600	3 000
2019	1 x 600	1 x 600	3 000
2020		1 x 600	3 600
2027	2 x 600	2 x 600	3 600
	5 875	7 800	
New Addition		1 925	

Plan with Coppermine Hydro

The alternative plan with the Coppermine hydro project, as selected in the optimization studies described in Section 9.6, follows the same criteria used for the reference plan except that;

- the hydro project is oversized so that it can supply part of the heating load,
- diesel units are not retired after the hydro plant is brought into service. Fixed diesel operating costs are included, however at 50% of the full rate assumed with normal operation.

The revised schedule of plant additions and retirements for the alternative plan with the selected hydro scheme (1 888 kW) is as follows;

Year	Retirement kW	Additions kW	Installed Capacity kW
1984			1 675
1987	3 x 225	2 x 600	2 200
1992		1 888	4 088
	675	3 088	
Net Plant Additions		2 413	

The scheduling of plant up to 1991 is the same as for the reference all diesel plan. Thereafter the hydro project, and availability of diesel units, that would otherwise be retired, provides considerable excess peak and energy capability, in respect of the reliability criterion.

4.9.2.4 Generation Costs

The comparison of generation costs, whether on a unit cost or system plan basis, requires capital and operating charges to be estimated.

Capital related charges include

- interest
- depreciation
- interim replacement
- insurance.

Operating charges include

- operation and maintenance
- general administration of overhead
- fuel.

The operation and maintenance costs for existing diesel units were provided by the NCPC. Corresponding costs for the new hydro and diesel projects were estimated, and interim replacement, insurance and overhead costs were taken from U.S. Federal Energy Regulatory Commission (USFERC) guidelines.

For comparison of the diesel and hydro-diesel systems the following were used:

		Hydro	Diesel
Decision discount rate	(%)	8	8
Service life	(years)	40	20
Interim replacement	(% capital cost)	0,22	0,35
Insurance	(% capital cost)	0,1	0,25
Fuel		-	54¢/l

Operation and maintenance cost of the hydro plant depends on the size and the following cost, which include 40% allowance for administration and general expenses, were used:

Scheme	Installation	O & M $/kW/year
1	922	186,2
2	1 888	106,4
3	2 243	93,1
4	2 800	79,8

For the diesel units there are both fixed cost ($/kW), based on the unit size, and variable costs (¢/kWh), based on the amount of energy generated. From operation and maintenance cost (O & M costs) data which was provided the NCPC, a fixed charge of $70/kW/year was assumed. The breakdown of the O & M costs is:

- 65% fixed cost
- 35% variable cost

Capital costs for the two generating systems were taken as follows.

Diesel Units

The reference all diesel plan provides for periodic additions of new 600 kW units. These were assumed to be located at the site of the existing generating station, thus site development storage and water supply changes will be less than for a new station. The capital cost of new units has been assumed as $ 1 904/kW (source NCPC). The expenditure for each unit will occur over 2 years,

Year 1 55%
Year 2 45%

on power at end of year 2.

Coppermine Hydro

The optimization studies considered four alternative schemes and installations, with the following estimated capital costs (excluding the cost for additional studies which is common to all schemes):

Scheme	Installation kW	1984 dollars Capital Cost $	Cost $/kW
1	922	12 421 000	13 472
2	1 888	17 692 000	9 307
3	2 243	19 274 000	8 593
4	2 800	22 153 000	7 912

The above capital costs include real interest during construction (IDC) at 8%. For the anayalses using a range of discount rates the IDC amounts were deleted and capital expenditures applied on an annual basis using the following schedule of disbursements.

Year	Scheme 1	Scheme 2	Scheme 3	Scheme 4
1	23,3	20,6	20,2	19,6
2	39,3	43,1	43,7	44,8
3	37,4	36,3	36,1	35,6
	100,0	100,0	100,0	100,0

On power is thus assumed at the end of year 3.

4.9.2.5 Heating Load Credit

The evaluation of the hydro-diesel system assumed that excess hydro energy would be used for heating, i.e., for displacing home heating fuel oil. It should be pointed out that during the summer, when the heating loads are low, full advantage cannot be taken of this energy use, especially in the early years of the project.

The cost of fuel for heating is based on 56 cents/litre. The equivalent electrical cost is 7,125 cents/kWh. An accepted standard for the valuation of electrical energy for heating is to assume a value of 90% of the equivalent electrical cost, i.e., 0.9 x 7,125 or 6,41 cents/kWh. This value was applied to all surplus hydro generation that was useable (i.e., not in excess of the heating demand).

The present worth of the annual heating credits provide the gross benefit from the displacement of heating fuel. This was reduced by the cost of providing heating units, which was assumed to be $2 200 per household (source NCPC).

Although the availability and useability of surplus hydro generation will vary over the evaluation period, an approximate allowance for conversion costs was assumed based on the provided average number of households to be supplied. There are 245 buildings in Coppermine.

Heating load credit using waste heat from the diesel units were not considered, as a separate study on this subject is being sponsored by EMR.

Costs assumed the following household heating conversions.

Scheme	Installation kW	No Households
1	922	93
2	1 888	245
3	2 243	245
4	2 800	245

4.9.3 Results of Analysis

4.9.3.1 Hydro

The derived net benefits, as a function of discount rate and installation size, are shown in Figure 4.12. The corresponding Benefit/Cost Ratios are as follows.

Scheme No	Installation kW	Benefit/Cost Ratio vs Discount Rate 6%	8%	10%
1	922	1,40	1,05	0,85
2	1 888	1,46	1,13	0,89
3	2 243	1,44	1,08	0,86
4	2 800	1,32	1,01	0,79

These comparisons show that for all discount rates tested, scheme 2 is the optimum. It may also be noted that the results are not overly sensitive to the selected installation. Consequently the finally selected installation could be varied from the indicated optimum, if justified by economies due to equipment selection, as may be defined in more detailed studies.

Having selected Scheme 2 as the optimum, the optimum on power date was obtained by producing benefit/cost ratios as a function of on power date and discount rate. The results are as follows:

Comparison of On-Power Dates for Scheme 2
Benefit/Cost Ratio vs Discount Rate

On-Power Year	6%	8%	10%
1990	1,46	1,13	0,89
1991	1,52	1,15	0,92
1992	1,54	1,17	0,93
1993	1,47	1,12	0,88

The results show that the benefit/cost ratio is maximized with an onpower date of 1992 (January), irrespective of the discount rate. Net benefits are also maximised for discount rates of 8% and 10%. For a 6% discount rate net benefit is maximised with a 1991 commissioning. No tests were made to determine if a variation in fuel price or load growth would affect this conclusion.

Supplementary results of the analysis provided the payback period and average generation costs. These were derived with and without the credit from use of surplus electrical energy for heating (after allowing for heating unit conversion costs). These values are calculated at a discount rate of 8%.

Payback Period	20 years, if surplus energy is used for heating 40 years, without use of surplus energy for heating

Average Generation Costs	Unit Costs in cents/kWh
All diesel generation	37,8
With the hydro project:	
- Average system costs, including heating credit	33,6
- Average system costs, excluding heating credit	41,2
- Hydro generation costs, including heating credit	31,7
- Hydro generation costs, excluding heating credit	43,4

The results show, the importance of the heating credit in establishing the economic viability of the hydro project.

The general conclusion from the base case comparison is that the economic viability of the hydro project is largely contingent on,

- the use of surplus hydro generation for heating,
- the future (relative) prices of distillate and heating fuels,
- the operational requirements to maintain existing diesel units in service, if the hydro project is implemented. Further on Figure 4.12 shows the break even rate of return (IRR) is 9,5%.

The results of the comparions for the low load growth scenario are summarized as follows.

Breakeven Internal Rate of Return 8,2% (9,5%)

Benefit Cost Ratios	I	B/C	
	6	1,34	(1,54)
	8	1,02	(1,17)
	10	0,80	(0,93)

( ) Results with the median load growth

4.9.3.2 Sensitivity Tests

The hydro project's viability (Scheme 2) was subjected to sensitivity tests whereby the fuel price was assumed to increase at a real rate of 2% p.a., and that the capital cost of the hydro plant varied by - 10% to + 20%.

The results of the analyses to test the effect of fuel price and capital cost, expressed in terms of the present worth of net benefits as a function of discount rate, are shown in Figure 4.12, and are summarized as follows.

Case	Breakeven Discount Rate (IRR) %	Benefit/Cost Ratio vs Discount Rate		
		6%	8%	10%
Base Case Comparison	9,5	1,54	1,17	0,93
With 2% Escalation in Fuel Cost	10,1	1,68	1,28	1,01
With Hydro Capital Cost + 10%	8,7	1,41	1,07	0,85
With Hydro Capital Cost - 10%	10,3	1,70	1,29	1,03
With Hydro Capital Cost + 20%	7,9	1,29	0,93	0,78

4.10 Conclusions

The optimization comparisons have shown that the Coppermine hydroelectric project should

- be sized for an installation of about 1 900 kW
- if implemented, be scheduled for an on-power date of about January, 1992, based on the reference load forecast and fuel prices.

Breakeven Rate of Return (IRR) 9,5%

Benefit/Cost Ratios	Interest Rate %	B/C Ratio
	6	1,54
	8	1,17
	10	0,93

SECTION 5 FORT SIMPSON-TROUT LAKE

5.1 SETTING

Fort Simpson is located at 61°-52'N latitude, 121°-23'W longitude at the confluence of the Liard and Mackenzie Rivers as well as at the junction of the Liard and Mackenzie Highways. These highways link the community to Vancouver and Edmonton, respectively.

Fort Simpson was established as a trading post about 1804 by the Northwest Company and is now an administrative centre for the territorial government. It is a transportation centre possessing important air, road, and water links to the west of Canada and is thus strategically located to provide an important logistics centre for the exploration of oil, gas and minerals in the surrounding area. The community is also situated at the northern edge of the Boreal Forest and significant stands of timber are located along the Liard river valley.

The present population is estimated at 1010, Table 5.1, of which about half are Dene. The natural growth rate is estimated at 1,9% p.a. Even though the community is relatively small, the economic base and resource potential in the area is diverse. Major economic activities include government, transportation, hunting, trapping, forestry, and tourism. Resource potential in the region includes oil, gas, minerals and agricultural land.

The hydroelectric project is also intended to serve the small community on the south-eastern shore of Trout Lake. This smaller community of about 60 persons has an airstrip but is presently not supplied with electricity. The location of both Fort Simpson and Trout Lake are shown on Figure 1.1.

5.2 ELECTRICAL LOAD

The Fort Simpson community presently receives electricity from diesel generators which have a total capacity of 5535 kW. The electrical load in 1982/83 amounted to 5768 MWh with a load factor of 66%. Annual growth over the past few years showed a decrease of 0,8% reflecting the loss in population over the period.

TABLE 5.1

POPULATION FORECAST - FORT SIMPSON

Year	Population
1982	975
1983	993
1984	1 012
1985	1 030
1986	1 050
1987	1 070
1988	1 090
1989	1 111
1990	1 132
1991	1 153
1992	1 175
1993	1 197
1994	1 220

Space heating is supplied by oil furnaces and wood. In 1978/79, 838 829 gallons of heating oil were consumed. This is equivalent to approximately 24 210 MWh of heat as an electrical load and it is roughly 4,1 times the normal electrical load. For the purpose of estimating the possible space heating electrical load, it was assumed that 20% of the heat will be supplied by wood or propane.

The load forecast to 1994, including a supply of electricity to the Trout Lake community, and the required capacity are given in Table 5.2. The load shape is shown in Figure 5.1(a).

Beyond 1994, the load was assumed to grow at 2,5% p.a. This was considered adequate for the purposes of an initial evaluation during Phase One.

5.3 HYDROLOGY

Since flows on the Trout river are given by two streamgauges, the regional approach for estimating the hydrologic parameters of the project was not needed. One gauge is located near the highway and the other at the outlet of Trout Lake. These gauges allowed the derivation of flows at the three sites of interest to be readily determined. These three sites are at the highway (Whittaker Falls), the upstream hydro site and at Trout Lake, and the drainage areas at these locations are 9 090 km^2, 6 130 km^2 and 5 860 km^2.

Figures 5.2 and 5.3 show the average flows and dimensionless daily flow duration curves for Trout Lake. Superimposed on these are the flows obtainable for 95% regulation. The Trout Lake flows when combined with the flows in the Trout river at the highway gives rise to the composite flow patterns of Figure 5.4.

The operational regime of Trout Lake was envisaged as one in which the spring and summer flows to Trout Lake were stored for release during the winter. Hence, downstream of the lake flows are obtained from the intermediate basin, and winter flows are derived from releases from Trout Lake. Figure 5.5 shows the preliminary operational releases down the Trout river to match the load shape given in Figure 5.1(a). As can be seen from the flows at Whittaker Falls, there will be spilling during the summer since the electric load is small. The peak flow to the turbines in the winter is about 39,2 m^3/s, whilst the summer demand is about 17,6 m^3/s. However, the downstream plant is capable of handling 39,2 m^3/s.

TABLE 5.2

FORT SIMPSON-TROUT LAKE

LOAD SUMMARY (10 YR FORECAST) - 1994

Load Type	Consumer Load MWh/annum	Annual Generation MWh/ánnum	Design Capacity MW
ELECTRICAL			
Fort Simpson			
Residential/ Commercial/ Institution	6 362	7 485	1,50
Industrial	8 760	10 305	2,10
Trout Lake			
Residential	63	74	0,02
TOTAL ELECTRICAL	15 185	17 864	3,70
HEATING			
Fort Simpson			
Residential	2 580	3 035	1,20
Commerical/ Institution/ Industrial	23 460	27 600	10,90
Trout Lake			
Residential	439	516	0,20
TOTAL HEATING	26 479	31 151	12,30
GRAND TOTAL	41 664	49 015	16,00

Flood flows at the areas of interest took into account that floods flows into Trout Lake could be routed, thus diminishing the peaks. Floods at the highway were not routed. The resulting floods are:

RETURN PERIOD (Years)	LOCATION	NATURAL FLOOD (m^3/s)	ROUTED FLOOD (m^3/s)
1:20	Outlet of Trout Lake	712	30
	Highway	-	514
1:1000	Outlet of Trout Lake	1 339	80
	Highway	-	1 230

5.4 HYDROELECTRIC DEVELOPMENT

Geotechnical

The site on Trout River at Whittaker and Coral Falls, situated between Mackenzie Highway and Mackenzie River, Figure 5.6, lies in the Great Slave Plain physiographic subdivision of the Interior Plains region. Bedrock at the site consists of Upper Devonian limestone of the Redknife and Kakisa Formations. Near the Mackenzie River shales and siltstones of the Upper Devonian Fort Simpson Formation are present beneath glacial deposits.

Glacial deposits consist of silty clay till plain (5 m) and till veneer (1,5 m) deposits with some ridged moraine. Glacio fluvial sands and gravels are found along Trout River near the Mackenzie Highway. Fine grained glaciolacustrine plain deposits 5m thick and locally up to 50 m thick, and sand and gravel glaciolacustrine beach deposits 1-2 m thick are present between the highway and the Mackenzie River. In some areas the fine grained, poorly drained glaciolacustrine materials are overlain by frozen peat and unfrozen fen deposits 1,5 - 7 m thick. In areas with thick peat cover, thick ice rich permafrost is present in mineral soil beneath the peat.

Granular material is readily available in glacio fluvial terrace and channel deposits near Mackenzie Highway. Unfrozen fine grained impermeable borrow can come from unfrozen till deposits which are not covered by thick peat.

The relevant map sheet is 66E-Mills Lake.

The sites at and near Trout Lake, Figure 5.6, lies in the Great Slave Plain subdivision of the Interior Plains physiographic region. Bedrock consists of shale of the Fort St. John Group. Thick Quaternary deposits overlie the shales at the site. These deposits consist largely of silty clay till plain materials that are greater than 5 m thick. Frozen peat and unfrozen fen organic deposits 1,5 to 7 m thick overlie till throughout much of the area. Permafrost with fairly high ice contents will be found in the fine grained till plain deposits which underlie the peat. Crevasse fillings of till and silt are common.

Granular material is scarce near this site. The closest source of good quality granular material lies some distance to the north of this site along the Mackenzie Highway near its junction with the Fort Liard winter road. Impermeable borrow is readily available and can be taken from till plain deposits which have only shallow or no organic cover and are available near the site.

The relevant map sheet is 95A - Trout Lake.

Preliminary Design

Previous studies have recommended harnessing the potential power of Whittaker Falls (14,3 m) and Coral Falls (5,2 m) on the Trout River to supply the energy needs of Fort Simpson. This site is as far as 120 km east of Fort Simpson, but it appears to be the best site for a small scale hydro development. The advantages are that there is river flow during the winter, and Trout Lake in the upstream catchment can be used to regulate the river flows.

The maximum power which could be obtained from the Whittaker-Coral Falls is about 4,8 MW using only flow regulated by Trout Lake. This power output is insufficient to justify such a long transmission line (120 km). Another site upstream of these falls was therefore sought so that the regulated flow could be used more than once.

Figure 5.6 shows the location of the upstream site, and the layout of the development. There would be a low dam spillway, approach channel and control structure at the exit of Trout Lake. At the upstream site the diverted flows would be taken by a canal along the 396 m (1300 ft) contour and then a pipe to a powerhouse about 30 m below the general elevation of the canal. The powerhouse of 8,5 MW would be on the right bank of the river. Downstream at the Whittaker Falls site, there would be a low dam and intake, similar to the upstream site, and the diverted flow would be taken to a powerhouse on the left bank of the river by a tunnel and/or pipe. The capacity of this powerhouse would be 5,5 MW.

The supply of electricity to the Trout Lake community was also considered to be a necessary addition to the features of the project. The Trout Lake community is estimated to be 60 persons and the required capacity to serve the electrical and heating load over 40 years was found to be 500 kW. To provide electricity to the community two approaches were examined, namely

- construct a 68 km transmission line from the upstream development to the community, or
- construct a mini hydro plant at the lake control structure and a transmission line of 42 km to the community.

There is a serious disadvantage to the second alternative in that the mini hydro plant would not be operational when water is being stored in the spring and summer. This would necessitate building a diesel plant at the Trout Lake community to allow a continuous supply of electricity. A comparison of the costs of the two approaches showed that the first alternative, the 68 km line from the upstream site, was the less expensive. The mini hydro alternative was more expensive for two reasons, principally. Firstly, a pipe would have to be constructed from the lake outlet control structure to the powerhouse to obtain a minimum operating head, since the river gradient is very small. Secondly, the powerhouse would have to be about 1 660 m downstream of the lake outlet instead of being an integral part of the control structures. The cost of the mini hydro plant was estimated to be about $5,16 million, whilst the 68 km transmission line was estimated to be about $2,45 million.

Because Trout Lake is about 500 km2 the height of storage which would be required to conserve the spring and summer runoff is only 0,73 m. Important aspects of this scheme are:

- the lake level would be raised 0,73 m normally, but if the 1:1000 year flood occurred when the lake was full, then an additional rise of 1,6 m could be expected;
- the river level at the upstream site would be raised about 2,0 m;
- the river level south of the highway would be raised 3,0 m;
- there would be no spring and summer releases from Trout lake;
- the river level during the winter would be much higher than normal.

The characteristics of the development are given in Table 5.3.

TABLE 5.3

PROJECT CHARACTERISTICS

FORT SIMPSON DEVELOPMENT

Item		Upstream Site	Downstream Site
Drainage Area	(km2)	6 130	9 090
Average Runoff	(mm)	111	111
Average Natural Flow	(m3/s)	21,6	31,9
Maximum Plant Flow	(m3/s)	39,2	39,2
Upstream Elevation	(m)	397,4	266,3
Downstream Elevation	(m)	366,9	246,8
Gross Head	(m)	30,5	19,5
Net Head	(m)	26,6	17,9
Canal	(m)	5 000	--
Pipe/Tunnel			
- length	(m)	350	1 250
- diameter	(m)	4,4	4,4
Installed Capacity	(MW)	8,5	5,5
Energy Capability	(GWh p.a.)	53,9	53,9

5.5 PROJECT EVALUATION

Capital Cost

The capital costs of the Trout river developments were calculated using the methodology outlined in Section 2. The estimates were prepared for two types of developments, namely

- supplying electricity only to Fort Simpson;
- supplying electricity to both Fort Simpson and Trout Lake.

The difference between the two cost streams is the additional transmission line from the upper powerhouse to the community of Trout Lake. Tables 5.4 and 5.5 summarise these costs.

Cost Effectiveness

The economic comparison of the proposed hydroelectric plant with the existing diesel generators and the present method of heating was done according to the methodology outlined in Section 2. The parameters which are relevant to the method are:

- 38,69 ¢/l for the cost of diesel oil,
- 40,0 ¢/l for the cost of home heating oil,
- 4,1 for the ratio of heat load to the normal electric load.

The equivalent oil value which was used to compare the cost of electricity from the hydro scheme is given below.

Discount Rate (%)	Value of Energy - ¢/kWh				
	Diesel Plant	Diesel Oil	Electricity Cost	Heating Cost	Weighted Cost
6	7,3	11,7	19,0	5,2	7,9
8	8,2	11,7	19,9	5,2	8,1

TABLE 5.4
PROJECT COST (1984 dollars)
FORT SIMPSON

		$ x 10^6	$ x 10^6
1.	Camp facilities	1,577	
2.	Dams and diversion	1,566	
3.	Lake control structure	1,390	
4.	Water conveyance system	8,072	
5.	Powerhouse	0,750	
6.	Access	1,365	
7.	Transportation	0,789	
8.	Sub-total of Civil Works (C.W.)		15,509
9.	Electrical and Mechanical		
	- Equipment	4,481	
	- Services	2,205	
	- Erection	1,176	
10.	Transmission	13,295	
11.	Sub-total of E&M		21,157
12.	Contingencies		
	- Civil (20%)	3,102	
	- E&M (8%)	1,693	
13.	Engineering (10%)	4,146	
14.	Sub-total of Direct Cost	45,607	
15.	Indirect Costs (45% of C.W.)	6,979	
16.	Capital Cost	52,586	
17.	Interest during construction (6%)	3,155	
18.	Construction Cost	55,741	
19.	Unit Cost	$3 981/kW	

TABLE 5.5

PROJECT COST (1984 dollars)

FORT SIMPSON/TROUT LAKE

		$\$ \times 10^6$	$\$ \times 10^6$
1.	Camp facilities	1,577	
2.	Dams and diversion	1,566	
3.	Lake control structure	1,390	
4.	Water conveyance system	8,072	
5.	Powerhouse	0,750	
6.	Access	1,365	
7.	Transportation	0,789	
8.	Sub-total of Civil Works (C,W.)		15,509
9.	Electrical and Mechanical		
	- Equipment	4,481	
	- Services	2,205	
	- Erection	1,176	
10.	Transmission	15,743	
11.	Sub-total of E&M		23,605
12.	Contingencies		
	- Civil (20%)	3,102	
	- E&M (8%)	1,888	
13.	Engineering (10%)	4,410	
14.	Sub-total of Direct Cost	48,514	
15.	Indirect Costs (45% of C.W.)	6,979	
16.	Capital Cost	55,493	
17.	Interest during construction (6%)	3,330	
18.	Construction Cost	58,823	
19.	Unit Cost	$4 202/kW	

The Trout river development is capable of providing electrical energy to serve both the electrical load and the heating loads, at both communities, for about 30 years, Figure 5.7. The cost of energy over the economic life of the project, based on useable energy or energy sales is shown on Tables 5.6 and 5.7. These Tables also show that the resulting cost indices when the existing and proposed systems are compared. As can be seen from these Tables, the cost indices for both development do not obtain the value of 1,0.

For the cost index to become 1,0 and using the equivalent oil value of 7,9 ¢/kWh (6% p.a. rate of return) for the supply of heat and electricity, then the construction cost of either project would have to be $51,94 million dollars. If the transmission line costs in Table 5.5 is maintained, and the equipment cost is unchanged, then the required savings on all of the civil works would have to be 31,8%, taking into account a supply of electricity to the Trout Lake community. The accuracy of the cost estimate has been given as ± 20%, and the conclusion which must be made is that the required additional savings are unlikely to be realised. The cost index would therefore never be 1,0 principally because of the long transmission line from the project area to Fort Simpson.

5.6 CONCLUSION

The economic evaluation indicates that this scheme is not a better alternative to the existing methods of producing electricity or heating. The serious disadvantage of the scheme is that the cost of the transmission line to Fort Simpson is nearly equal to the cost of the civil works. If the transmission line were shorter and/or the load larger, the project would be attractive.

TABLE 5.6

ECONOMIC EVALUATION

FORT SIMPSON DEVELOPMENT

Item	6%	8%
Construction cost	55,74	55,74
Present Values (PV) of:		
Interim replacement	1,86	1,47
Insurance	0,85	0,68
Operation and Maintenance	5,48	4,34
Administration	2,14	1,69
P.V. of expenditures	66,07	63,92
P.V. of energy sales	784,5	597,5
Effective cost of energy	8,4	11,0
Equivalent oil value for electricity and heat	7,9	8,1
Cost index	0,94	0,73

NOTES:

1. Expenditures are in millions of dollars.
2. Energy is in GWh over 40 years.
3. Cost of energy is in ¢/kWh.

TABLE 5.7

ECONOMIC EVALUATION

FORT SIMPSON/TROUT LAKE DEVELOPMENT

Item	6%	8%
Construction cost	58,82	58,82
Present Values (PV) of:		
Interim replacement	1,96	1,55
Insurance	0,91	0,72
Operation and Maintenance	5,48	4,34
Administration	2,14	1,69
P.V. of expenditures	69,31	67,12
P.V. of energy sales	795,9	606,3
Effective cost of energy	8,7	11,1
Equivalent oil value for electricity and heat	7,9	8,1
Cost index	0,91	0,73

NOTES:

1. Expenditures are in millions of dollars.
2. Energy is in GWh over 40 years.
3. Cost of energy is in ¢/kWh.

SECTION 6 FROBISHER BAY

6.1 SETTING

Frobisher Bay has its roots in the establishment of a trading post at Ward Inlet, near the present townsite by the Hudson's Bay Company. The community is located at 63°-45'N latitude and 68°-34'W longitude on Koojesse Inlet near the northeast head of Frobisher Bay, Baffin Island. The U.S. Air Force constructed a major air base during the 2nd World War and followed this up with the construction of the Distant Early Warning (DEW) line in the 1950's. Future plans call for the establishment of a new capital city at Frobisher for the Eastern Arctic. Transportation is limited to air and sea routes.

The present population is estimated at 2626 of which two-thirds are Inuit. Table 6.1 shows a forecast of the population to year 1994.

The economic base of Frobisher Bay consists of government, transportation, communications, fishing, sealing, trapping and tourism. Fish harvesting includes arctic char and mammal harvesting includes whales, walnus, and seals. Polar bears are also hunted on the quota system.

6.2 ELECTRICAL LOAD

The community presently receives electricity from diesel generators which have a total capacity of 9945 kW. The electrical load in 1982/83 amounted to 20 971 MWh with a load factor of 61%. Annual growth over the past 6 years averaged 1,6%.

Space heating is supplied by oil furnaces and district heating using boiler heat from the NCPC facilities. In 1978/79, 1 109 037 gallons of heating oil were consumed. This is equivalent to approximately 32 000 MWh of heat as an electrical load and it is roughly 1,8 times the normal electrical load.

The load forecast to 1994 and the required capacity are shown on Table 6.2. It will be seen that the capacity requirement is quite high when compared with the energy requirement. This is caused by the heating load. Beyond 1994, the load was assumed to grow at 2.5% p.a. This was considered adequate for the purposes of an initial evaluation during Phase One.

TABLE 6.1

POPULATION FORECAST - FROBISHER BAY

Year	Population
1982	2 493
1983	2 559
1984	2 626
1985	2 695
1986	2 766
1987	2 839
1988	2 914
1989	2 991
1990	3 070
1991	3 151
1992	3 234
1993	3 319
1994	3 406

TABLE 6.2

FROBISHER BAY - LOAD SUMMARY (10 YR FORECAST) - 1994

Load Type	Consumer Load MWh/annum	Annual Generation MWh/annum	Design Capacity MW
ELECTRICAL			
Residential/ Commercial/ Institution	24 060	28 305	5,5
Wholesale	1 500	1 765	0,20
Total Electrical	25 560	30 070	5,70
HEATING			
Residential	35 765	42 080	13,80
Commerical/ Institution/ Industrial	20 845	24 520	8,00
Total Heating	56 610	66 600	21,80
Grand Total	82 170	96 670	27,50

6.3 HYDROLOGY

The project flows for this scheme are based on the recorded flows, and the hydrology of the site given in a previous study, Reference 26. The important points to be noted in the previous study are:

- rainfall on the catchment was assumed to be equal to that at Frobisher Bay, namely 15,87 inches per annum or 404 mm p.a.
- runoff from the catchment was 1 cfs per square mile or 10,93 l/s/km2 or 345 mm p.a.

The records of the Sylvia Grinnell river are not continuous and only one year (1971) of full data was available. The average flow in that year was 26,87 m^3/s (280 mm) corresponding to a specific yield of 8,87 $l/s/km^2$. When the data from other gauges were examined, the flows in 1971 appeared to be generally slightly below the average flows. However, because of the quality of the data on the river, a reduction of the specific yield to 8 $l/s/km^2$ was used in this study; this is 73% of the flows used in the previous study.

If the runoff and precipitation of the previous study are used, then the evapotranspirational loss which was taken was 58,3 mm p.a. The corresponding loss, using 0.8 of the value in Figure 2.3, is 60 mm. The point precipitation value of 403 mm at Frobisher Bay must be reduced to obtain areal precipitation on the Sylvia Grinnell catchment. This reduced value can be obtained by assuming the 1971 flow to be the average flow resulting from a runoff of 280 mm from 3030 km^2. If to this value the evapotranspirational loss of 60 mm is added, then the mean annual precipitation would be 340 mm. Figure 2.2 tends to support this proposition.

The operation of the Sylvia Grinnell river flows is similar to that of the Trout river schemes, with the added advantage of being able to obtain additional winter flows from the downstream reservoir. The flow regime and preliminary plant operational flows are shown in Figures 6.1 and 6.2. The average plant flow for the best of the alternatives examined in Reference 26 is now 18,64 m^3/s.

The estimated flood flows on the Sylvia Grinnell river is as follows:

Flood Flows - m^3/s

Location	Drainage Area km^2	1:20 year		1:1000 year	
		Natural	Routed	Natural	Routed
Sylvia Grinnell River at the Lake Outlet	1 166	193	52	374	125
Sylvia Grinnell River at Frobisher	3 030	417	316	795	658

6.4 HYDROELECTRIC DEVELOPMENT

Geotechnical

Two of the dam sites which were previously studied, Reference 20, have been adopted in this study. They are the site at the outlet of Sylvia Grinnell lake, and the downstream site at river level 53,3 m (175 ft), Figure 6.3.

The rocks in the project area are of Precambian age. At the downstream site of the main dam bedrock composed mainly of gneisses and quartz feldspar are found on the right bank, whilst till and glacio fluvial deposits overlie bedrock on the right bank. The exposed bedrock on the left bank is highly fractured, whilst the depth of overburden on the right bank is unknown. Solifluction lobes are also present on the right abutment of this proposed dam site. The glacio fluvial deposits might contain high ice contents with resulting foundation problems.

The dam site at the outlet of the Sylvia Grinnell Lake indicates fill in moraine on both banks being thinner on the left bank. The depth to bedrock on the left bank is probably much less than on the right bank where deep solifluncted and boulder stream moraine exists.

Preliminary Design

The proposed development was first investigated in 1975, and is located on the Sylvia Grinnell river. Briefly stated, the development of the Sylvia Grinnell consists of an upstream lake, Sylvia Grinnell lake, which regulates the flow from the upper drainage basin, and the regulated flow is used at a downstream dam. A rockfill, overflow dam and control structure at the outlet of the Sylvia Grinnell lake would allow the spring and summer flows to the lake to be stored for winter releases. There are no significant water falls downstream and head has to be created by the construction of a dam about 56 m high. The downstream plant is 10 km from Frobisher Bay and has a spillway and powerhouse both on the left bank of the Sylvia Grinnell river. It is the construction of such a high dam for such a small power output which is a severe disadvantage to the Scheme. The scheme layout is shown in Figure 6.3.

References 23 and 26 provided the main thrust for the review of the developments on the Sylvia Grinnell river. The sites which were chosen in these references are considered to be the most suitable, and the recommended development was also considered to be acceptable, namely alternative 6 (SG 6). This acceptance of SG 6 as the best alternative was based on the finding that it provided energy at at the least cost, for a 10 MW development in Reference 26.

Since the flows which were used in the previous study have been reduced, Section 6.3, the maximum output of this preferred alternative must be reduced to 7,5 MW.

The characteristics of the development are given in Table 6.3, and the comparison of the available energy to the load demand is shown in Figure 6.4.

6.5 PROJECT EVALUATION

Capital Cost

The capital cost of the scheme was obtained by using the data given in References 23 and 26, and allowing for river diversion costs and the cost of the control structure at the outlet of the Sylvia Grinnell lake. It was also considered prudent to include for a permanent road from Frobisher Bay to the powerhouse. And, finally, the construction period was lengthed to three years.

The capital cost estimate is given in Table 6.4.

TABLE 6.3

PROJECT CHARACTERISTICS

FROBISHER BAY DEVELOPMENT

Item		At Sylvia Grinnell Lake	At Downstream Dam
Drainage Area	(km^2)	1 166	3 030
Average Runoff	(mm)	252	252
Average Natural Flow	(m^3/s)	8,95	24,2
Maximum Plant Flow	(m^3/s)	--	20,46
Upstream Elevation	(m)	142,3	103,1
Downstream Elevation	(m)	--	50,5
Gross Head	(m)	--	52,6
Net Head	(m)	--	46,75
Canal	(m)	--	--
Pipe/Tunnel			
- length	(m)	--	100
- diameter	(m)	--	2 @ 2,5
Installed Capacity	(MW)	--	2 @ 3,75
Energy Capability	(GWh p.a.)	--	54,0

TABLE 6.4

PROJECT COST (1984 dollars)

SYLVIA GRINNELL

		$ x 10^6	$ x 10^6
1.	Camp facilities	4,258	
2.	Dams and diversion - Lake	1,894	
	- Main dam	18,628	
3.	Spillway	5,528	
4.	Water conveyance system - Lake	3,188	
	- Main dam	0,702	
5.	Powerhouse	1,008	
6.	Access	4,535	
7.	Transportation	2,129	
8.	Sub-total of Civil Works (C.W.)		41,870
9.	Electrical and Mechanical		
	- Equipment	8,180	
	- Services	1,156	
	- Erection	0,900	
10.	Transmission	0,630	
11.	Sub-total of E&M		10,866
12.	Contingencies		
	- Civil (20%)	8,374	
	- E&M (8%)	0,869	
13.	Engineering (10%)	6,198	
14.	Sub-total of Direct Cost	68,177	
15.	Indirect Costs (45% of C.W.)	18,842	
16.	Capital Cost	87,019	
17.	Interest during construction (8%)*	6,962	
18.	Construction Cost	93,981	
19.	Unit Cost	$12 531/kW	

* Longer construction period.

Cost Effectiveness

The equivalent value of oil was calculated using the methodology of Section 2, and the following parameters:

- 44,78 ¢/l for diesel oil
- 45,4 ¢/l for home heating oil
- 3,2 for the ratio of head load to normal electric load

The equivalent cost of energy is as follows.

Discount Rate (%)	Value of Energy - ¢/kWh				
	Diesel Plant	Diesel Oil	Electricity Cost	Heating Cost	Weighted Cost
6	5,9	13,6	19,5	5,9	9,1
8	6,6	13,6	20,2	5,9	9,3

The Sylvia Grinnell scheme does not have the capability to supply both the electrical and heating loads, even as presently required, but the project can supply the estimated electrical load for close to 40 years. It is almost cost effective at 6%. The analysis neglects that the surplus capability in early years could be used to supply some heating load.

Consequently, the weighted cost of energy is not applicable in determining the cost index of the project. To obtain the index, the cost of electricity in the above table must be compared with the effective cost of energy from the hydro plant given in Table 6.5. The comparison of the two systems is shown below.

TABLE 6.5

COST OF ENERGY

FROBISHER BAY DEVELOPMENT

Item	6%	8%
Construction cost	93,98	93,98
Present Values (PV) of:		
Interim replacement	3,16	2,50
Insurance	1,35	1,07
Operation and Maintenance	4,29	3,40
Administration	1,67	1,32
P.V. of expenditures	104,45	102,27
P.V. of energy sales	508,2	383,3
Effective cost of energy	20,6	26,7

NOTES:

1. Expenditures are in millions of dollars.
2. Energy is in GWh p.a. over 40 years.
3. Cost of energy is in ¢/kWh.

Item	6%	8%
Present value (P.V.) of construction cost and annual cost (Millions of dollars)	104,45	102,27
P.V. of energy sales (GWh over 40 years)	508,2	383,3
Effective cost of hydro energy (¢/kWh)	20,6	26,7
Equivalent value of diesel generation (¢/kWh)	19,5	20,2
Cost index	0,95	0,76

6.6 CONCLUSION

Since the cost index of this scheme is less than 1,0, it is not recommended that any further study should be done on this project.

SECTION 7 - RAE LAKES

7.1 SETTING

Rae Lakes is located at 64°-09'N latitude, 117°-20'W longitude on Rae Lake, 177 km northwest of Yellowknife. Rae Lake is a part of an interior chain of lakes between Great Bear and Great Slave Lakes. The lakes lie at the boundary between the Canadian Shield and the Interior Plains in the transition forest region. Traditionally, the area has been the hunting ground of the Dogrib Dene from the Rae area. This previous hunting outpost has become a permanent community with the construction of community buildings and infrastructure in the 1970's.

Rae Lakes is a Dene community of 207 people with a natural growth rate of about 1,7% p.a. Table 7.1 shows a projection of population to year 1994.

The economic base of Rae Lakes is the traditional persuits of fishing, hunting and trapping. Annual harvests consist of lake trout, whitefish, caribou and small fur bearing animals. There is relatively high mineral potential in the area, and this includes uranium. Transportation into the community is principally by air with a winter road joining the community to the Mackenzie Highway at Rae-Edzo.

7.2 ELECTRICAL LOAD

The community presently receives electricity from diesel generators which have a total capacity of 180 kW. The electrical load in 1982/83 amounted to 178 MWh with a load factor of 45%. Annual growth over the past 6 years averaged 2,8%.

Space heating in Rae Lakes is presently supplied almost exclusively by wood consisting of jack pine and some spruce. The community consumes approximately 400 cords annually with an average consumption of approximately 12 cords per household. The present electrical equivalent of the space heating market in Rae Lakes has been estimated at 1200 MWh, assuming that 20% of the load will always be supplied by other fuels (eg., wood, propane). On the basis of sales this heating load is roughly 6,7 times the electrical load. The monthly load shape is shown on Figure 8.3(a).

TABLE 7.1

POPULATION FORECAST - RAE LAKES

Year	Population
1982	205
1983	206
1984	207
1985	209
1986	211
1987	213
1988	215
1989	217
1990	219
1991	221
1992	223
1993	225
1994	227

Computer rounding has occurred.

TABLE 7.2

RAE LAKES - LOAD SUMMARY (10 YR FORECAST) - 1994

Load Type	Consumer Load MWh/annum	Annual Generation MWh/annum	Design Capacity MW
ELECTRICAL			
Residential/ Commercial/ Institution	204	240	0,06
HEATING			
Residential	883	1 039	0,40
Commerical/ Institution/	491	578	0,24
Total Heating	1 374	1 617	0,64
Grand Total	1 578	1 857	0,70

The load forecast to 1994 and the required capacity are shown on Table 7.2. Because of the heating load the capacity requirement is high compared to the energy which must be provided. Load growth beyond 1994 was assumed at 2.5% p.a. This was considered adequate for the purposes of an initial evaluation during Phase One.

7.3 HYDROLOGY

The Rae Lake and Faber Lake drainage areas are sub-basins of the Camsell river basin. The entire drainage basin which lies in an area of low precipitation and runoff, as indicated in Figure 2.2. It is therefore necessary to store the spring runoff of the Faber Lake drainage area for release during the winter. The drainage area of Faber Lake is about 2 550 km2, and the average flows and dimensionless, daily flow duration curve are shown on Figures 7.1 and 7.2, respectively.

The natural and regulated flows at the outlet of the Rae Lake and the dimensionless daily flow duration curves are shown in Figures 7.3 and 7.4 respectively. The turbine flow through the Rae Lake is 9,26 m3/s from a total drainage area of 3720 km2.

Because of the extensive lake system, the floods which would normally occur at Rae Lakes are reduced due to natural flood routing. The estimated floods are as follows.

Flood Flows - m^3/s

Location	Drainage Area km^2	1:20 year		1:1000 year	
		Natural	Routed	Natural	Routed
Camsell River at Rae Lake	2 512	54	18	83	25
Camsell River at Lac Ste Croix	3 715	75	25	120	40

7.4 HYDROELECTRIC SCHEMES

Geotechnical

The two Rae Lakes sites and the Faber Lake control dam site are located in the Bear Upland physiographic subdivision of the Kazan region near the boundary of the Great Slave Plain subdivision of the Interior Plain region, Figure 7.5. Bedrock at the western site on Camsell River consists of three types of massive porphyritic Proterozoic granites which have been mapped as one unit by the Geological Survey of Canada. Upstream and slightly east of the rapids, sedimentary Ordovician dolomite, sandstone and shale of Great Slave Plain is present. A northeast trending Proterozoic diabase or gabbro sill lies east of the dam site Coarse to fine grained till and fine grained glaciolacustrine deposits overlie bedrock at the sites. The till represents material deposited directly from glacier ice while the fine grained glaciolacustrine materials were formed in a large glacial lake system which extended southeastward from Great Bear Lake to Great Slave Lake. The fine grained glaciolacustrine deposits will contain some high ice content permafrost, especially if they are poorly drained and covered with peat deposits.

Granular materials can be obtained from glaciofluvial deposits such as the esker located 6 km west of the westernmost dam site. Impermeable borrow will be available in glaciolacustrine deposits, but ice contents may affect its quality. Till developed on Ordovician rocks upstream of the western dam site will be finer in texture than till developed on shield rocks, and where thicker till deposits of this type are present sites for impermeable borrow may also be recommended.

The relevant map sheet is 86-C - Hardisty Lake.

Two possible developments were examined for Rae Lakes. The first uses the fall between Rae Lake and Lac Ste-Croix, and the second uses the fall between Rae Lake and Taka Lake, Figures 7.5 and 7.6. Both schemes require the storage of water in Faber Lake and its controlled release during the winter.

The Rae Lake/Lac Ste-Croix scheme would require a dam and intake between the two lake systems and the powerhouse at Lac Ste-Croix. The Taka diversion scheme would require a dam and intake on Rae Lake, as well as a dam at the Rae Lake/Lac Ste-Croix junction to prevent the escape of water into Lac Ste-Croix. The powerhouse for the Taka diversion scheme would be on Taka Lake.

TABLE 7.3

PROJECT CHARACTERISTICS

RAE LAKES DEVELOPMENT

Item		Rae/ Ste-Croix	Taka Scheme
Drainage Area	(km2)	3 270	3 270
Average Runoff	(mm)	90	90
Average Natural Flow	(m3/s)	9,33	9,33
Maximum Plant Flow	(m3/s)	9,26	9,26
Upstream Elevation	(m)	211,6	211,6
Downstream Elevation	(m)	205,4	204,2
Gross Head	(m)	6,0	7,4
Net Head	(m)	5,4	6,7
Canal	(m)	500	300
Pipe/Tunnel			
- length	(m)	--	450
- diameter	(m)	--	3,5
Installed Capacity	(kW)	250	500
Energy Capability	(GWh p.a.)	2,8	3,5

Water would be conveyed to the powerhouses in insulated pipes. The conveyance system for the Taka diversion would also require the excavation of a channel and would thus more costly.

A third possibility was considered of putting a larger dam at Faber Lake, and a powerhouse on the Rae Lake side of the junction of Faber Lake and Rae Lake. The cost of such a scheme was found to be more than the two schemes discussed above and was therefore discarded.

The water levels in Faber Lake would be raised 4,2 m whilst that in Rae Lakes would be raised 0,7 m.

Each scheme requires a transmission line of about 25 km.

The characteristics of the developments are given in Table 7.3. The relationship between the energy which is available from the scheme and the load demand is shown on Figure 7.7.

7.5 PROJECT EVALUATION

Capital Cost

The Rae Lake - Lac Ste Croix scheme costs 4,44 million dollars whilst the Rae Lake - Taka Lake scheme is estimated to cost 10,23 million dollars. These costs are shown on Tables 7.4 and 7.5. Both schemes can satisfy the small electrical and heating loads, but the following economic evaluation is for the better Rae Lake - Lac Ste Croix scheme.

Cost Effectiveness

The equivalent value of oil, in the table below, was found by using the following parameters:

- 38,8 ¢/l for diesel oil
- 64,0 ¢/l for home heating oil
- 6,7 for the ratio of heat load to the normal electric load.

Discount Rate (%)	Value of Energy - ¢/kWh				
	Diesel Plant	Diesel Oil	Electricity Cost	Heating Cost	Weighted Cost
6	15,4	11,8	27,2	8,3	10,8
8	17,2	11,8	29,0	8,3	11,0

TABLE 7.4
PROJECT COST (1984 dollars)
RAE LAKE - STE-CROIX

		$\$ \times 10^6$	$\$ \times 10^6$
1.	Camp facilities	0,147	
2.	Dams and diversion	0,171	
3.	Spillway	--	
4.	Water conveyance system	0,767	
5.	Powerhouse	0,179	
6.	Access	0,106	
7.	Transportation	0,073	
8.	Sub-total of Civil Works (C.W.)		1,443
9.	Electrical and Mechanical		
	- Equipment	0,361	
	- Services	0,053	
	- Erection	0,061	
10.	Transmission	0,900	
11.	Sub-total of E&M		1,375
12.	Contingencies		
	- Civil (20%)	0,289	
	- E&M (8%)	0,110	
13.	Engineering (10%)	0,322	
14.	Sub-total of Direct Cost	3,539	
15.	Indirect Costs (45% of C.W.)	0,649	
16.	Capital Cost	4,188	
17.	Interest during construction (6%)	0,251	
18.	Construction Cost	4,439	
19.	Unit Cost	$17 759/$W	

TABLE 7.5
PROJECT COST (1984 dollars)
RAE LAKE - TAKA

		\$ x 10^6	\$ x 10^6
1.	Camp facilities	0,431	
2.	Dams and diversion	0,485	
3.	Spillway	--	
4.	Water conveyance system	2,623	
5.	Powerhouse	0,380	
6.	Access	0,106	
7.	Transportation	0,216	
8.	Sub-total of Civil Works (C.W.)		4,241
9.	Electrical and Mechanical		
	- Equipment	0,739	
	- Services	0,072	
	- Erection	0,094	
10.	Transmission	0,900	
11.	Sub-total of E&M		1,805
12.	Contingencies		
	- Civil (20%)	0,848	
	- E&M (8%)	0,144	
13.	Engineering (10%)	0,704	
14.	Sub-total of Direct Cost	7,742	
15.	Indirect Costs (45% of C.W.)	1,908	
16.	Capital Cost	9,650	
17.	Interest during construction (6%)	0,579	
18.	Construction Cost	10,229	
19.	Unit Cost	\$20 458/kW	

TABLE 7.6

COST OF ENERGY

RAE LAKES DEVELOPMENTS

Item	250 kW		500 kW	
	6%	8%	6%	8%
Construction cost	4,440	4,440	10,229	10,229
Present Values (PV) of:				
Interim replacement	0,147	0,116	0,331	0,262
Insurance	0,067	0,053	0,151	0,119
Operation and Maintenance	0,301	0,239	0,301	0,239
Administration	0,117	0,093	0,117	0,093
P.V. of expenditures	5,072	4,941	11,129	10,942
P.V. of energy sales	28,83	22,51	68,37	51,56
Effective cost of energy	17,59	21,9	16,3	21,2

NOTES:

1. Expenditures are in millions of dollars.
2. Energy is in GWh p.a. over 40 years.
3. Cost of energy is in ¢/kWh.

A comparison of the cost of the proposed hydroelectric schemes is shown on Table 7.6. The difference in the effective cost of energy between the 250 kW scheme is small, whereas the capital investment is more than twice. Considering only the 250 kW scheme, therefore, and comparint it with the existing methods of generating electricity and heating then the following table can be prepared.

Item	6%	8%
Present value (P.V.) of construction cost and annual cost (Millions of dollars)	5,07	4,94
P.V. of energy sales (GWh over 40 years)	28,83	22,51
Effective cost of hydro energy (¢/kWh)	17,6	21,9
Equivalent value of diesel generation and heating oil (¢/kWh)	10,8	11,0
Cost index	0,61	0,50

It can be seen that the cost index is less than 1,0; and even if the slightly more economical 500 kW scheme is examined, the cost index at 6% becomes 0,66.

7.6 CONCLUSION

The cost of supplying the small load is more than the existing methods of obtaining electricity and heat. The project is therefore not recommended for further study.

SECTION 8 - RANKIN INLET

8.1 GENERAL

Rankin Inlet is located at 62°-49'N latitude and 92°-05'W longitude on the west coast of Hudson Bay and was established as a mining centre in 1955 by North Rankin Nickel Mines. This mine closed in 1962 causing considerable hardship to those employed at the mine. It is only in the past decase that the community has recovered somewhat by operating a fishery, crafts industry and receiving territorial government investment, through the relocation of government offices from Churchill to Rankin Inlet.

8.1.1 Population

The 1981 population of Rankin Inlet was 1 110 as recorded by Statistics Canada. There were slightly more males (54%) than females (46%) and the predominant cultural group, numbering 850, was the Inuit.The largest age cohort groups were found between the ages of 0 and 19 in 1981. Recent statistics would suggest that Rankin Inlet is growing at a rate of 1.3% p.a. It is therefore estimated that 1 210 people presently live in Rankin Inlet and that the number of people between the ages of 15 and 64 is 660, with slightly more males than females. Table 8.1 gives a forecast of population to year 1994.

8.1.2 Employment and Income

The economic base of Rankin Inlet is a mixture of wage and traditional employment. Government, transportation and commercial fishing provide most of the wage employment although tourism is becoming more important each year. Traditional harvesting includes arctic char, grayling, lake trout and whitefish as well as whales, walrus, caribou, polar bear and fur bearing animals. The commercial fishery processes arctic char. The mineral potential of the area includes iron, lead, nickel, copper, cobalt and uranium.

The estimated work force is 450 people but a breakdown into categories was not available. The main employment areas would most likely be:

TABLE 8.1

POPULATION FORECAST - RANKIN INLET

Year	Population
1982	1 182
1983	1 196
1984	1 211
1985	1 226
1986	1 241
1987	1 256
1988	1 271
1989	1 287
1990	1 303
1991	1 319
1992	1 335
1993	1 351
1994	1 368

Computer rounding has occurred.

- Government (Fed/GNWT/Hamlet)
- Non-Renewable Resources (mining, oil and gas)
- Retail
- Utilities
- Transportation
- Service
- Construction
- Hunters/Trappers/Fishermen

It is also probable that the unemployment rate is similar to Baker Lake and Coppermine, i.e., about 50%. Per capita income in 1981 was recorded at $6 293 and consumer prices were 50%-59% higher than those in Winnipeg.

8.1.3 Housing

Housing consists of 144 single units and 21 apartment units owned by the NWT Housing Corporation. In addition, GNWT maintains 54 singles, 2 mobiles, 2 duplexes, 21 townhouses and 10 appartments while the Federal Government has 14 singles. Heating is by means of fuel oil supplied by POL and the Co-op.

8.1.4 Commercial

Retail and wholesale trade is somewhat more developed at Rankin Inlet than at either Coppermine or Baker Lake. There are two major department stores (Bay and Co-op) as well as a craft shop, travel agency, video shop, service station, Honda dealership, bank, building supplies, sporting goods, government offices and a dining establishment.The tourism sector includes boat trips, fishing charters, ceramics, soapstone carvings, and wall hangings.

8.1.5 Industrial

The industrial activity in the community is limited to small construction contractors and a fish plant. The fish plant was visited in late August, 1984, and it was observed that the plant was processing fresh char as well as experimenting with a new line of smoked char.

The community is also a transfer point for crew changes from the Cullaton Lake gold mine.

8.1.6 Recreation

Recreation facilities include a community hall, indoor arena, curling rink, school gymnasium, softball field, and a library.

8.1.7 Social Services

The community has a new school and offers education from kindergarten to grade 9 with an approximate enrollment of 330 students. There is also an adult education centre which caters to the needs of the people in the Keewatin Region.

Medical facilities consist of a 4 bed/3 bassinet nursing station operated by National Health and Welfare. The medical staff includes four (4) nurses and one doctor. The community receives dental care from a visiting dentist.

Other social services, including alcohol and drug counselling, are provided in the community through advisory committees and professional staff. There is a five person RCMP detachment as well as Justices of the Peace.

8.1.8 Transportation

Rankin Inlet has a 1 520 m gravel runway. The airport has minimum navigational aids and is without an ILS system. Two commercial carriers, as well as two charter companies, operate out of Rankin Inlet.There is no float plane base.

Barge service is provided to the community by NTCL out of Churchill, Manitoba. Bulk goods such as construction materials, non-perishable food stuffs and fuel are supplied to the community each year by means of water transport.

Surface transportation is available through a bus/taxi within the community. There are no roads or highways external to the community.

8.1.9 Water, Sewer, Roads, Solid Waste

The water supply for the community is obtained from Nipissar Lake located 2 km northwest of the townsite. The water is of good quality and is treated with chlorine prior to distribution. Storage is provided by means of an open air reservoir (Williamson Reservoir) which is adjacent to the town. Water distribution is by means of piped services in older utilidors and buried mains. Those buildings not connected to the piped system receive their water by truck.

Sewage is collected by means of a piped system in either the old utilidors or shallow buried mains and by truck for bagged sewage. Sewage collected by pipe is macerated at the shore and disposed into Hudson Bay by means of a 425 m outfall. Sewage in bags is disposed of at the solid waste landfill site.

Roads in the community are gravel topped and adequately drained and are suitable for light traffic.

8.1.10 Lifestyle

The lifestyle in the community may be described as Inuit Transitional. The influence of government is noticeable in the community and provides a significant amount of wage employment. This contrasts with those who have seasonal or no employment and who also hunt, fish and trap on a seasonal or year-round basis. The importance of traditional pursuits in the community is highlighted in the following Table.

TABLE 8.2

Estimated Rankin Inlet Harvest (1982/83)

Species	No.	Estimated Avg. Edible Weight (kg)/Species	Total Est. Edible Weight Available Each Year (kg)	%
Caribou	1 483	48	71 189	59
Polar Bear	19	157,1	2 985	3
Seal				
. Ringed	499	12,9	6 416	
. Bearded	19	98,4	1 870	
. Harbour	2	21,9	44	7
Whale (Beluga)	29	502,4	14 571	12
Walrus	48	181,6	8 718	7
Arctic Char	5 508	2,5	13 857	11
Lake Trout	354	2,4	859	0,7
Geese	236	0,9	205	
Ptarmigan	228	0,4	91	
Miscellaneous	-	-	26	0,3
		Total	120 831	100

Source: R.L. Gamble, A Preliminary Study of the Native Harvest of Wildlife in the Keewatin Region, NWT, Fisheries and Oceans, 1984

These figures must be considered as preliminary since they are based upon only one year of data and partial returns from hunters, trappers and fishermen. To replace the total amount (120 831 kg) with beef at $10/kg would represent some 1,2 million dollars annually or $5 820 per native household. The domestic fishery would therefore account for an estimated 11% or $640 per native household.

Most of the char is caught at the mouth of the Diana River between June and August as the char migrate downstream to feed in the estuary. During the winter char is caught beneath the ice at Peter Lake.

The commercial fishery accounts for between 20 000 kg and 40 000 kg annually.

The value of fur from trapping was estimated at $18 000 in 1982/83.

8.2 ELECTRICAL LOAD

8.2.1 Existing Electric Load

The existing electrical load in 1982/83 amounted to 6478 MWh with a peak load of 1205 kW and a load factor of 61%. Sales amounted to 5894 kW with the domestic market contributing 51%, commercial 48% and street lights accounting for the remainder. There were no wholesale or industrial sales. Average annual growth in sales over the past 6 years has amounted to 7,0%.

8.2.2 Existing Heating Load

Space heating in Rankin Inlet is supplied by oil furnaces and a heat recovery system from the NCPC diesel generators. In 1978/79, 614 839 gallons of heating oil were consumed in Rankin Inlet. This is equivalent to approximately 17 750 MWh of heat as an electrical load. On the basis of sales, this heating load is roughly 3,4 times the electrical load.

8.2.3 Load Forecast

The load forecast for Rankin Inlet (1994) is summarized in Table 8.3 and shows a total load of 29 665 MWh/annum consisting of 7270 MWh of electrical and 22 385 MWh of space heating. With respect to the district heating now provided by NCPC, it was

TABLE 8.3

RANKIN INLET - LOAD SUMMARY (FORECAST) - 1994

Load Type	Consumer Load MWh/annum	Annual Generation MWh/annum	Design Capacity MW
ELECTRICAL			
Residential/ Commercial/ Institution	7 270	8 555	1,70
HEATING			
Residential	10 165	11 960	3,90
Commerical/ Institution/ Industrial	12 220	14 375	4,60
Total Heating	22 385	26 335	8,50
Grand Total	29 665	34 890	10,20

assumed that this market will be supplied fully by electric space heating since diesel units will be put on stand-by for peaking or emergency power. Design capacity at the bus bar has been estimated at 10,2 MW to supply the total load of which 1,7 MW is required for the electrical load only. The monthly load shape is illustrated by Figure 8.3(b). Load growth beyond 1994 was assumed at 2.5% p.a. This was considered adequate for the purposes of an initial evaluation during Phase One.

8.3 HYDROLOGY

The drainage areas of the Diana river and Gibson lake catchments are 1487 km2 and 3383 km2, respectively. The flow from the Diana river alone is not large, but this could be improved if the Gibson Lake flows can be diverted into the Diana river catchment. A runoff of 155 mm, giving a specific yield of 4,91 l/s/km^2, was adopted for both drainage areas.

Additional flow could be obtained by diverting the Meliadine River and lake into Peter Lake, but the increment of average flow is estimated to be no more than 2,3 m^3/s which is less than 10% of the average flow obtainable from Gibson Lake and the Diana river system. The cost of this diversion has not been investigated.

The plant discharge is 27,9 m^3/s and the combined Gibson Lake - Diana River flows are shown in Figure 8.1. The dimensionless, daily flow duration curve is given in Figure 8.2.

The estimated floods for the two catchments are given below.

Flood Flows - m^3/s

Location	Drainage Area km^2	1:20 year		1:1000 year	
		Natural	Routed	Natural	Routed
Gibson Lake at the Outlet	3 383	456	130	868	310
Diana River at the Outlet	1 487	31	8	49	15

8.4 DIANA/GIBSON HYDROELECTRIC SCHEME

8.4.1 Study Sequence

The sequence of study for investigating the merits of small scale hydro at Rankin Inlet involved taking the proposed Diana River Scheme to the second level of investigation as a result of the desk studies in Phase one. These studies showed some promise that the scheme could supply the normal electrical load in Rankin Inlet. Consequently, a field investigation to confirm assumptions of natural heads, geological conditions, environmental impacts, and overall project feasibility was done.

The project's feasibility hinged upon the natural head available at the dam/powerhouse site, but more importantly on the possibility of transfering water from Gibson Lake to the Diana River drainage system.

The combined results of Phases one and two investigations are presented in some detail.

8.4.2 Geotechnical

The two sites in the Tavani area are situated in the Kazan Upland subdivision of the Kazan physiographic region on the west site of Hudson Bay, Figure 8.4.

The site on Diana River nearest the town of Rankin Inlet is underlain by layered gneiss and quartz biotite schist of Proterozoic age. Minor intrusions of basalt and andesite of the Kaminak Group are found throughout the area. A east-west trending band of Kaminak Group felsic volcanics crosses Diana River. Little or no outcrop is present near the study area because quaternary deposits are relatively thick. The second dam site at Gibson Lake is underlain by Proterozoic quartz diorite, granodiorite, and quartz monzonite rocks which are well foliated to gneissic. A prominent northeast-southwest trending fault lies at the southern tip of the largest lake. Minor amounts of layer gneiss and quartz biotite schist are found near the western boundary of the area. The quaternary cover at this site is thinner than at the site near Rankin Inlet with scattered to abundant outcrops present.

Rock at the site nearest Rankin Inlet is covered with Quaternary alluvial, marine, and glacial deposits. Glacial deposits consist of till plain sediments which are generally sandy, silty, and noncalcareous with 25% clay. Northeast-southwest trending ridged moraine also consists of this material. Tills have liquid limits of 8 to 18 percent and plasticity indices of 0 to 8 percent (topographic map sheet 65C, map 9 - 1980). Peat rings, mudboils and other periglacial features often cover till deposits. Glacio fluvial esker deposits of sand and gravel are abundant throughout the study area.

Nearshore coarse grained marine deposits and finer grained coastal plain tidal flat sediments are present in some portions of the area, particularly near the Inlet. The fine grained sediments are of stony silt and sand covered with organics and have periglacial features. Fine to coarse grained alluvial deposits exist in channels and on floodplains. Some of these alluvial deposits include alluvium in terraces which formed as streams cut to present level in glacial and marine sedimentary infill.

Quaternary deposits cover rock of the second study area near Gibson Lake. More rock is exposed in this area and throughout much of the area a veneer (1 m) of till overlies the granitic rocks. Minor ribbed moraines are present and a large esker of sand and gravel extends across half of the study area. Scattered alluvial and deltaic deposits are also present.

Granular borrow can be obtained at either site from nearby eskers. Impermeable borrow will be taken from marine alluvial or till deposits where high ice content permafrost is not present.

8.4.3 Preliminary Design - Phase 1

As conceived in Phase 1, this development involved the diversion of flows from Gibson Lake into Diana Lake via Peter Lake. The natural head is obtained by taking advantage of three small lakes which are perched above the Diana river. A canal would link the intake in a dam across the Diana river to these three lakes, which were assumed to nearly at the same elevation and possibly in need of deepening. The lakes would be used as a forebay and water would be taken to the powerhouse on the right bank of another small lake on the Diana river.

TABLE 8.4

PROJECT CHARACTERISTICS

RANKIN INLET DEVELOPMENT

Item		
Drainage Area	(km2)	4 870*
Average Runoff	(mm)	155
Average Natural Flow	(m3/s)	23,93
Maximum Plant Flow	(m3/s)	27,9
Upstream Elevation	(m)	35,5
Downstream Elevation	(m)	18,3
Gross Head	(m)	17,2
Net Head	(m)	13,7
Canal	(m)	--
- Gibson Diversion		1 500
- Intake		600
Penstock/Tunnel		
- length	(m)	150
- diameter	(m)	2 @ 3,0
Installed Capacity	(MW)	3,0
Energy Capability	(GWh p.a.)	18,2

* Diana catchment = 1487 km^2
Gibson catchment = 3383 km^2

Spring and summer flows would be stored behing the dam on the Diana river, to be released for use in the winter. The construction of a dam at the outlet of Gibson lake to permit the diversion would raise the natural water level by 8,1 m. The natural water level in the Diana river at the dam site would be raised by about 4,5 m.

The characteristics of the scheme are given in Table 8.4.

8.4.4 Power and Energy

The project characteristics show the Diana/Gibson scheme as capable of producing 3,0 MW and 18,2 GWh of energy per annum. Load forecasts after 1994 (Table 8.3) have been increased at a rate of 2,5% per annum to give a 40 year estimated demand, Figure 8.5. As shown in this figure, the project is physically capable of supplying only the electrical load over 40 years.

8.4.5 Project Evaluation - Phase 1

The capital cost of the Scheme is given in Table 8.5.

The equivalent value of oil was found by assuming the following parameters, and is summarised in the table below.

- 51,51 ¢/l for diesel oil
- 54,0 ¢/l for home heating oil
- 3,4 for the ratio of heat load to the normal electric load

Discount Rate (%)	Value of Energy - ¢/kWh				
	Diesel Plant	Diesel Oil	Electricity Cost	Heating Cost	Weighted Cost
6	7,5	15,6	23,1	7,0	10,7
8	8,4	15,6	24,0	7,0	10,9

TABLE 8.5
PROJECT COST (1984 dollars)
RANKIN INLET

		$ x 10⁶	$ x 10⁶
1.	Camp facilities	1,073	
2.	Dams and diversion	3,600	
3.	Spillway	--	
4.	Water conveyance system	4,042	
5.	Powerhouse	0,297	
6.	Access	1,000	
7.	Transportation	0,536	
8.	Sub-total of Civil Works (C.W.)		10,548
9.	Electrical and Mechanical		
	- Equipment	2,014	
	- Services	0,590	
	- Erection	0,449	
10.	Transmission	1,207	
11.	Sub-total of E&M		4,260
12.	Contingencies		
	- Civil (20%)	2,110	
	- E&M (8%)	0,341	
13.	Engineering (10%)	1,726	
14.	Sub-total of Direct Cost	18,985	
15.	Indirect Costs (45% of C.W.)	4,747	
16.	Capital Cost	23,732	
17.	Interest during construction (6%)	1,424	
18.	Construction Cost	25,156	
19.	Unit Cost	9 317/$W	

Since the project could not supply the energy for the heating load, the comparison of the existing system to the proposed hydroelectric project was based only in the cost of electricity.

The effective cost of energy and the economic evaluation of the scheme are summarized in below.

Item	6%	8%
Present value (P.V.) of construction cost and annual cost (Millions of dollars)	28,25	27,61
P.V. of energy sales (GWh over 40 years)	144,68	109,01
Effective cost of hydro energy (¢/kWh)	19,5	25,3
Equivalent value of diesel generation (¢/kWh)	23,1	24,0
Cost index	1,18	0,95

A comparaison of the present worth of fuel oil consumed over 40 years with that of the load horizon is shown in Figure 8.6. This showed that the project was not economic unless the capacity value of the existing diesel generator was added to the cost. Even so, the payback period on initial investment would be approximately 30 years.

8.5 FIELD SURVEYS - PHASE 2

8.5.1 Natural Head - Gibson Lake Diversion

Of the three projects which were investigated in the field, the Rankin Inlet project on the Diana river and Gibson Lake, Figure 8.4, warranted the most attention because of

- the distances separating key areas
- the need to divert the flows from Gibson Lake into Diana Lake via Peter Lake.

The survey of the Rankin Inlet site was limited by the availability of a helicopter, and, as it turned out, on the weather conditions. On 24 August, 1984, a brief aerial reconnaissance using a Bell helicopter was possible. This visit established that a low dam could be built at the outlet of Gibson Lake. However, because the right bank abutment was lower than the left, the maximum height to which a dam could be built appeared to be about 3 m above the normal water level. This estimate of the maximum height of the dam was not confirmed by physical measurements, since weather conditions and the unavailability of the helicopter subsequently prevented another site visit.

The flight path of the helicopter on the return to Rankin Inlet from Gibson Lake, about 92 km away, was along the envisaged water passage from Gibson Lake to the powerhouse on the Diana river, Figure 8.4. It became clear that in addition to constructing a diversion canal between Gibson and Diana lakes, many shallow areas would have to be excavated to prevent a freeze up at these locations during the winter. This aerial reconnaissance also confirmed the preliminary findings of the photo-geological interpretations, Phase 1 study.

On 25 August, 1984, it was possible to go to the areas of the proposed dam, conveyance system and powerhouse on the Diana River. A closed traverse was done along the alignments of the proposed dam and conveyance system, and along the right bank of the river. This levelling circuit, Figure 8.7, and observation of the terrain allow the following statements to be made:

- a dam can be constructed across the outlet of Diana lake. This dam alignment is a little upstream of the alignment proposed in the Phase 1 study;
- the head difference between the water levels at the dam site and the powerhouse site on the Diana river is 10,79 m;
- the water level at this proposed dam site can be raised 6 m;
- the three perched lakes forming a part of the water conveyance system are, as was previously assumed, at about the same elevation as the average water level in Diana Lake;
- the average height of the confining eskers along these perched lakes varies between 2 m and 0,25 m above the lake levels;

- there are many places along the general line of these lakes where water is seeping through the mat of tundra vegetation to the Diana river;
- because of the small difference in elevation between the lakes forming a part of the water conveyance system and the top of the confining eskers, embankments would have to be built along the lakes, on both sides, to contain the water in the conveyance system and to prevent seepage loss.

Profiles along the survey circuit are shown on Figure 8.8. The elevations are based on an assumed datum.

In as much as the foregoing observations tended to cast serious doubts on the feasibility of the project, there still remained three outstanding issues to be clarified, namely:

- was the elevation difference between the outlet of Gibson Lake and the divide between Gibson Lake and Peter Lake small enough to allow an economic diversion of water between the two systems?
- what maximum height of dam at the outlet of Gibson Lake would the topography permit?
- even if the diversion could be effected, were the rims of the enlarged Gibson and Peter Lakes competent to retain the spring runoff which would have to be stored in the lakes?

Since bad weather prevented field surveys, additional photogrammetric mapping was authorized to provide the answers to these questions.The results of this mapping are shown on Figures 8.7 and 8.9.

From a geotechnical point of view, the terrain is flat to rolling tundra with relief typicaly 3 m to 6 m. There is no ground cover of any stature and the overburden varies from 0 to 2 m. Innumerable ponds and lakes, mostly 1 m or less deep, are present. The two major lakes are deeper and fish can over winter. The rivers are small and less than one metre deep. The surface outcrops are flat lying and strewn with angular to sub angular fragments of frost heaved, weathered rock. Eskers are low and small but numerous and comprise of sand with a surfacing of boulders and gravel.

A comparison was made of the levelling which was done on the Diana river and the levels which were obtained from the photogrammetric mapping of the same area, Figure 8.7. This comparison permitted an order of magnitude error in the photogrammetric mapping models to be established. The difference in elevation between the water levels at the outlet of Diana Lake and the powerhouse site are as follows.

By closed traverse	10,79 m
By photogrammetry	9,20 m

It would therefore appear that the photogrammetric models would seem to give results which differ from precise levelling by about ± 1,6 m. For the purpose of this analysis this difference was assumed to apply to the photogrammetric model of the area between Gibson Lake and Peter Lake, Figure 8.9.

An examination of Figure 8.9 shows the following:

- the dam at the outlet of Gibson Lake would be long;
- the elevation of Gibson Lake is 600 m, assumed datum;
- the elevation of Peter Lake is 604 m;
- the highest water level in the divide is 608 m;
- the competent reservoir rim around Gibson Lake without construction any saddles, is 605 m.

It is evident that to transfer water from Gibson Lake to Peter Lake, the water level in the former lake must be raised 8 m. In addition, there must be a freeboard allowance on the lake of about 2 m. The reservoir rim should therefore be competent at about elevation 610 m. If the error of - 1,6 m is applied, then the elevation at which the rim could be competent would be 608,4 m.

Figure 8.9 shows that a comfortable elevation at which the enlarged Gibson Lake would be competent without saddle dams and a long outlet dam is 605 m. If the error of + 1,6 m is added to this value, then the reservoir rim should be competent at 607,6 m.

Since the elevation of 608,4 m which is required is greater than that which could be provided, namely, 607,6 m, then it must be deduced that there is little chance of effecting a transfer of water from Gibson Lake into Peter Lake and hence to Diana Lake.

8.6 INITIAL ENVIRONMENTAL EVALUATION

8.6.1 Environmental Concerns

Environmental concerns over any hydroelectric project for Rankin Inlet would have to focus almose exclusively on the Diana river char fishery.

Fisheries

Both commercial and domestic fishing occur on the Diana river system. This drainage system appears to be the major inland water system used by char and whitefish for spawning.

Commercial quotas are in place for char, whitefish, and trout for both the Diana and Gibson drainage basins as follows:

Commercial Quotas (kg/year)

	Char		Whitefish and Trout	
Diana River				
• Diana Lake	2 300		-	
• Peter Lake	2 300		7 600	
Sub-Total		4 600		7 600
Gibson Basin				
• Machum Lake	-		800	
• Macquoid Lake	-		1 000	
• River mouth (Chesterfield Inlet)	6 800		-	
Sub-Total		6 800		1 800
Offshore				
More than 5 miles from Rankin	9 100			

In addition to the commercial quotas, an estimated 22 700 kg of char are taken from the Diana for domestic purposes.

Transportation

During high tides, the Diana river system is navigable by freight canoe. The construction of a dam at the outlet of Diana Lake would present a barrier to river navigation. However, travel into the area appears to be made largely by 3 wheeled vehicles along trails located on the right bank of the river.

8.6.2 Environmental Impacts and Mitigative Measures

Impact of Diana River Dam on Fish Passage

The bulk of the char caught in the offshore fishery originate in the Diana river (Dept. of Fisheries and Oceans, ref. 1). This fishery is therefore dependent on keeping intact the historical sequence of migratory movements into and out of the Diana river. Little is definitely known about the char movements, but it is probable that overwintering occurs in upstream lakes such as Peter Lake and Diana Lake; both lakes have commercial quotas for char. Spawning may also take place in these lakes. The dam would not only enlarge and deepen Diana Lake but it would prevent the access of fish migrating from coastal waters into these upstream areas, unless a fishway was provided. As outlined for the Coppermine river, no documentated cases of char fishways are known, but it is considered that the development of a successful fishway is feasible. Fisheries studies, however, would be required to provide data necessary for designing the fishway. The kind of information which would be collected are:

- size of the run;
- size range of fish;
- species of fish (whitefish runs may also exist);
- duration of run.

Impact of Gibson Lake Dam on Fish Passage

The Gibson Lake Dam would increase the surface area and depth of Gibson Lake and increase the flows through Peter Lake, Diana Lake and the smaller lakes along the Diana river. These changes do not appear to have potentially serious impacts on fisheries in the present Diana river system. However, major changes to the fish populations in Gibson Lake and the unnamed river which drains Gibson Lake are possible.

The unnamed river appears to support a population of Arctic char, since there is a commercial quota for this species at its mouth at Chesterfield Inlet. Machum Lake and Macquoid Lake are also located on the river and have commercial quotas for lake trout and whitefish. Although the magnitude of the flow reduction in the unnamed river has not yet been determined, there is a potential for significant impacts on the fish populations. For example, the severe reduction in flow may make some stream sections impassible at the time of upstream migration (fall for char and whitefish).

A detailed knowledge of the river channel (locations and configurations of rapids, etc.) and projected seasonal flows would be required to assess the possibility of this type of impact and the potential for mitigation. Fishways can be built at natural obstructions but construction costs may be very high due to access to remote areas.

Flow reductions may also result in subtle changes in lake habitat which could affect fish production.

There is a possibility of major changes in the fish fauna of Gibson Lake due to:

- removal of the connection with the unnamed river;
- connection with the Diana River drainage;
- increase in mean and surface area.

To fully assess project impacts on Gibson Lake and the unnamed river drainage system, extensive field studies would be required. These would:

- describe the existing fish populations which are presently unknown;
- determine movements between parts of the drainage and between the river and coastal waters;
- determine whether any obstructions to migration would exist under altered flow regimes.

Mitigative Measures for Fish Passage

The costs of fisheries studies may be fairly high, probably in the range of $300 000 to $500 000. This is because the project affects two drainage systems encompassing several lakes, and due regard must be taken of the existing commercial and domestic fisheries.

Impact on Wildlife

The wildlife species of primary importance is the barren-ground caribou. At the present time there is insufficient information to assess whether or not this species would be affected by the project. Since the main concern is the possibility of interference with migrations, it will be necessary to determine the locations and times at which caribou cross the two affected drainage basins. It will also be necessary to determine if the project will change the pattern of ice formation and break-up at these locations enough to interfere with caribou crossing.

No detailed information on the use of the project areas by other wildlife species is available.

Mitigative Measures for Wildlife

Before any mitigative measures can be proposed, wildlife studies will have to be undertaken. During these studies discussions with knowledgeable Rankin Inlet residents and Canadian Wildlife Service staff should allow specific problems areas to be identified.

8.7 CONCLUSIONS

8.7.1 Project Viability

As a result of phase one and phase two investigations the following conclusions have been reached with respect to the viability of the project:

- the Diana/Gibson scheme is economically marginal at best and can only supply the normal electrical load over 40 years;
- it is highly unlikely that water can be transferred from Gibson Lake to Diana Lake. Without this transfer the project cannot even meet the normal electric load;
- the dam at the outlet of Gibson Lake would be much longer than was previously assumed;
- many areas between Peter Lake and Diana Lake would have to be excavated to prevent freeze-up. This was not allowed for in the cost estimates which were prepared in the Phase 1 study;

- the water level in Diana Lake can be raised as required;
- the head which was assumed in the first phase of the study is realisable;
- water can be transferred from Diana Lake to the powerhouse along the proposed water conveyance route, but embankments along the perched lakes, not previously allowed for, would have to be constructed.

8.7.2 Environmental Impact

Since the project's viability is questionable, the environmental impact will not be given undue emphasis. However, the major environmental impact would be possible interference with the char's migratory and reproductive cycles within two drainage basins. The cost of fisheries studies is estimated at between \$300 000 and \$500 000. It is noted that the community's reliance upon the char is less than Coppermine's and relatively less than Baker Lake's reliance upon the caribou.

SECTION 9 - APPLICATION OF WIND TURBINE GENERATORS

Alternative energy sources for the six communities were considered on the basis of the load, the present state of alternative energy technology, cost and the climatic conditions. From these considerations, only wind energy appeared to be worth investigating.

The use of wind energy as a means of reducing the oil consumption of diesel generating plant in remote locations has been frequently proposed. The simplest form of wind turbine generator is the vertical axis Darrieus rotor coupled through a speed increasing gear box to an induction machine. The Darrieus turbine, having fixed blades, cannot self-start under all conditions so that the induction machine is used for starting as a motor and automatically transfers to generating operation when it crosses synchronous speed.

The induction machine draws its excitation from the system to which it is connected. Hence, it follows that the wind turbine generator most always operate in parallel with another generating source.

Another consideration is that the wind turbine "fuel" source, viz. the wind, is continually varying so that firm power in the normal sense cannot be guaranteed. However, based on statistical wind data, it is possible to estimate the energy output of a wind turbine generator per year. The average power output of a wind turbine generator is of the order of 20 to 30 percent of its continuous power rating.

The wind turbine capacity in terms of continuous power rating relative to the minimum load demand of the connected system in an important factor which determines the stability of operation and the economic value of the wind turbine installation. For example, if the wind turbine installed capacity exceeds the system load demand then it will runaway unless it is shut down before the situation arises. In a multi-unit installation, one or more units may be shut down to preserve system stability. This clearly adversely affects the economics since wind turbines will have been shut down when they are most productive. The alternative to shutting down the wind turbines is to provide an artificial load such as a water heating system, space heating or equivalent.

The question of the maximum acceptable capacity of wind turbine installation is very site specific and must properly be addressed on an hour-by-hour operation basis, with full knowledge of the hour-by-hour load pattern and wind pattern. A computer program capable of such analysis does exist.

For present purposes, it is assumed that the wind turbine installation capacity does not exceed the minimum system load demand so that all the energy derived from the wind can be usefully absorbed by the load system.

Wind data

Wind data was derived from "Canadian Climate Normals, Volume 5, Wind" published by Environment Canada. It should be noted that data from the above source is only indicative and better sites may be available dependent on the local topography. The annual average wind speed (AAWS) from the data source was reduced to a standard value at 10 m above ground level by using a typical shear index of 0,17.

For Coppermine, the data indicate that the monthly mean wind speeds are below average from March to July which suggests that the availability of wind energy does not ideally match expected variations in the load characteristics. From August to February the wind speeds are above average, but not by much, and the generated energy can conceivably be used to meet a heating load. In the case of Rankin Inlet, the data for Chesterfield was used and in the case of Rae Lakes, the data for Yellowknife was used.

Energy production

All estimates presented below are based on the DAF-Indal 500 kW vertical axis Darrieus wind turbine generator. The variation of net annual energy produced as a function of the site annual average wind speed measured at 10 m above ground level is shown in the following table.

AAWS at 10 m, m/s mph	5.26 11.77	6.13 13.71	7.01 15.68	7.88 17.63	8.76 19.60	9.64 21.56
Annual energy, MWh (net)	477	752	1039	1305	1524	1685

It is estimated that the wind turbine would produce 260 MWhe per annum.

All the data presented assumes a 95 percent availability for the wind turbine.

Because of the increase in air density, the power output of a wind turbine increases as the temperature decreases. No allowance has been made for this.

Wind Turbine Costs

The costs given below are for a one-off, special order machine in 1984 dollars:

Cost of basic materials	-	625,000
Additional design features for arctic environment (15% of basic cost)	-	93,750
Additional transportation costs to NWT (50 tons x 500)	-	25,000
		$ 743,750
Basic installation cost	-	250,000
Adjustment for NWT	-	135,000
Total installation cost	-	$ 385,000
Total installed cost	-	$ 1,128,750

Although a cost of $2 278/kW is indicated by the above cost, the value of the wind machine must be examined in terms of the cost of energy. This is because the unavailability of wind at all time.

Cost of Energy

For wind turbine generators, the cost of energy (COE) is normally calculated from the following formula:

$$COE = \frac{(Cost \times FCR + O\&M \times LF) \times 100}{AE} \text{ ¢/kWh}$$

Where Cost = total installed cost of the wind turbine generator
FCR = fixed charge rate (Cost x FCR = annual repayments over a 30 year plant life)
O&M = operating and maintenance cost (taken as 2% of the capital cost)
LF = O & M levelizing factor (taken as 2 for a 30 years plant life)
AE = annual energy produced per year in kWh.

The cost of wind energy for the six communities are summarised below:

SITE	AAWS km/h @ 10m	ANNUAL ENERGY MWh	COST OF ENERGY, ¢/kWh		
			FCR = 6%	FCR = 8%	FCR = 10%
Baker Lake	21,58	705	16,01	19,21	22,41
Coppermine	16,42	325	34,73	43,41	52,10
Fort Simpson	11,08*	-	-	-	-
Frobisher Bay	15,96	225	50,17	60,2	70,23
Rae Lakes	15,47	180	62,71	75,25	87,79
Rankin Inlet	21,14	665	16,97	20,37	23,76

* The AAWS for Fort Simpson is too low to allow a reasonable estimation of the annual production.

From the above table, it is seen that there is a distinct possibility of investigating further the possibility of installing wind generators only at Baker Lake and Rankin Inlet. The cost comparison of electricity from the diesel generators, Sections 2 and 8, and from the wind generators from the foregoing table is summarised below:

However, the first step in such an investigation would be to collect wind data at a specific location in each of these two communities. After the collection of site specific data extending over at least one year, it is possible to construct a wind turbine of the type mentioned also in one year. To meet a higher load, a number of machines must be erected to create a "wind farm".

Location	Cost of Energy (¢/kWh)			
	6%		8%	
	Oil	Wind	Oil	Wind
Baker Lake	24,5	16,0	25,6	19,2
Rankin Inlet	23,1	17,0	24,0	20,4

SECTION 10 - CONCLUSION AND RECOMMENDATIONS

A situation that is common to all of the communities which were studied is the small normal electric load, and this has had an adverse effect on the economic viability of the hydro projects. This suggests that perhaps there should be a review of the methods of supplying energy to the communities, from time to time, depending on technological progress, the population growth and/or industrial growth.

Also, any attempt to replace home heating oil by electric heating requires that the cost of electricity must be less than the weighted cost (¢/kWh) of producing electricity by diesel generators and heating by the combustion of oil. If this criterion is related to a hydro scheme, then an extremely attractive hydro development must be indicated. Alternatively, there must be a use for hydro energy in excess of the normal electric demand for hydro schemes which are marginally attractive.

The conclusions and recommendations which can be made for each community are as follows.

Baker Lake

The Thelon dam scheme should not be proceeded with at this time, since the cost index is less than 1,0. The main technical reasons which make this project uneconomic are:

- the need for large diversion works
- the need to create head
- the small load

Efforts should be made to collect site specific wind data since it would appear that energy from wind generators might be competitive with diesel generators. After the collection of this data, over a period of at least one year, a feasibility study with the application of wind generators in a hybrid diesel-wind generation system should be carried out.

In the interest of future energy studies, environmental studies pertaining to the caribou, and fish life in the Thelon river should be undertaken.

Coppermine

The Bloody Falls project may be economically viable but a full feasibility study with improved data would be required to confirm this. For a discount rate of 8%, and assuming excess energy is used for heating, this project provides energy at a cost less than that from the diesel generators. However an increase in capital cost of 20% would be sufficient to make the scheme uneconomical. The development would require no structure across the Coppermine river to obviate environmental problems. Wind energy does not appear to be competitive with the cost energy from the hydro plant.

If it is decided to proceed with the studies, a fishery study on the fish life in the Coppermine river below and above Bloody Falls should be done. It would also be useful to determine if special fish passage designs are needed for the migration of arctic char across an artificial impediment in a river.

Fort Simpson - Trout Lake

The technical feasibility of the Trout river schemes, as it is presented, with an upstream and downstream plant so as to use the stored water in Trout Lake more than once, would not appear to be in doubt. However, the long transmision distance of 120 km makes the project uneconomic. The small load demand also acts against the viability of the project. It is therefore recommended that no further work should be done on the Trout river developments since the cost index is less than 1,0.

The wind regime in the area around Fort Simpson is too low to make the use of wind generators feasible. Should the Mackenzie Valley Gas Pipeline project be implemented, then the cost effectiveness of natural gas for space heating should be evaluated.

Frobisher Bay

Of the six communities, Frobisher Bay has the largest load demand, but the energy which is available from the best of the Sylvia Grinnell Schemes can only meet the projected normal electrical energy demand. The Sylvia Grinnell schemes suffers from a lack of natural head and so a 56 m dam is required. The size of such a high dam for a plant installation of only 7 MW is the main reason for making the project uneconomic. It is therefore recommended that no further work be done on this project since the cost index is less than 1,0.

An examination of the cost of wind energy shows that this form of energy is costlier than diesel generation. It would therefore seem that the present systems of producing electricity and heat are better than any alternative which has been examined in this Study.

Rae Lakes

Of the two sites which were examined, the better of them does not give a cost index greater than 1,0. The cost of energy from wind generators is also more expensive than the cost of electricity from the diesel generators. It is therefore recommended that no further studies should be done on these hydroelectric sites.

Rankin Inlet

Although it is possible to develop about 10 m of natural head at the outlet of Diana Lake, there is insufficient water in the Diana river system to allow the production of enough hydro energy to meet the normal electric load demand. Field surveys have shown that it is not feasible to divert water from the Gibson Lake system to the Diana river system. It is therefore recommended that no further studies relating to hydro development to serve Rankin Inlet should be undertaken.

A preliminary investigation of the wind energy potential indicates that there appears to be some merit in investigating the use of wind as an alternative energy source. Preliminary data gathering and a feasibility study should be done as outlined for Baker Lake.

PHOTO 1 : Thelon R. General view of dam site.

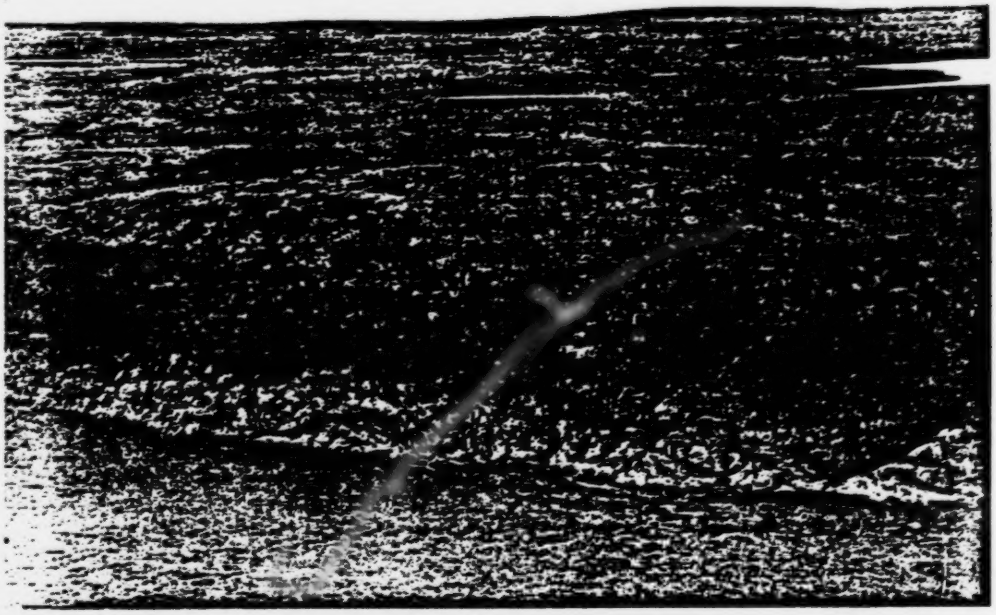


PHOTO 2 : Thelon R. Left bank in the area of the intake works. Tupik Lake on extreme right of photo. Granitic rock with no overburden.

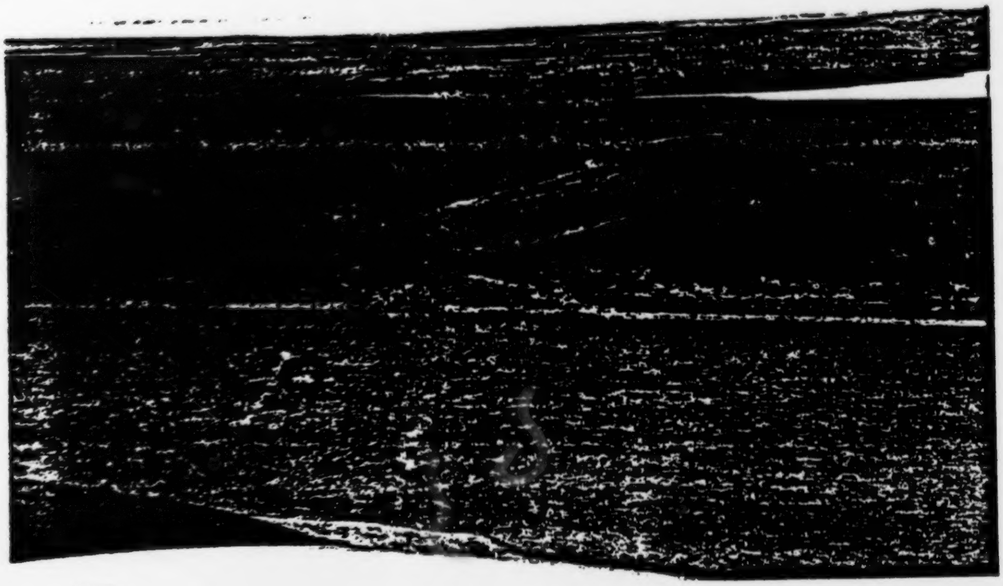


PHOTO 3 : Thelon R. View of left bank at outlet from Tupik Lake. Gravelly fill exposure on right bank of creek.

PHOTO 4 : Thelon R. Right bank opposite the outlet of Tupik Lake. Gravelly fill overburden varying thickness on granitic outcrop.

PHOTO 5 : Looking upstream. Note delta forming at head of small lake above falls.

PHOTO 6 : Middle reach of Bloody Falls. Igneous rock on each bank is highly jointed.

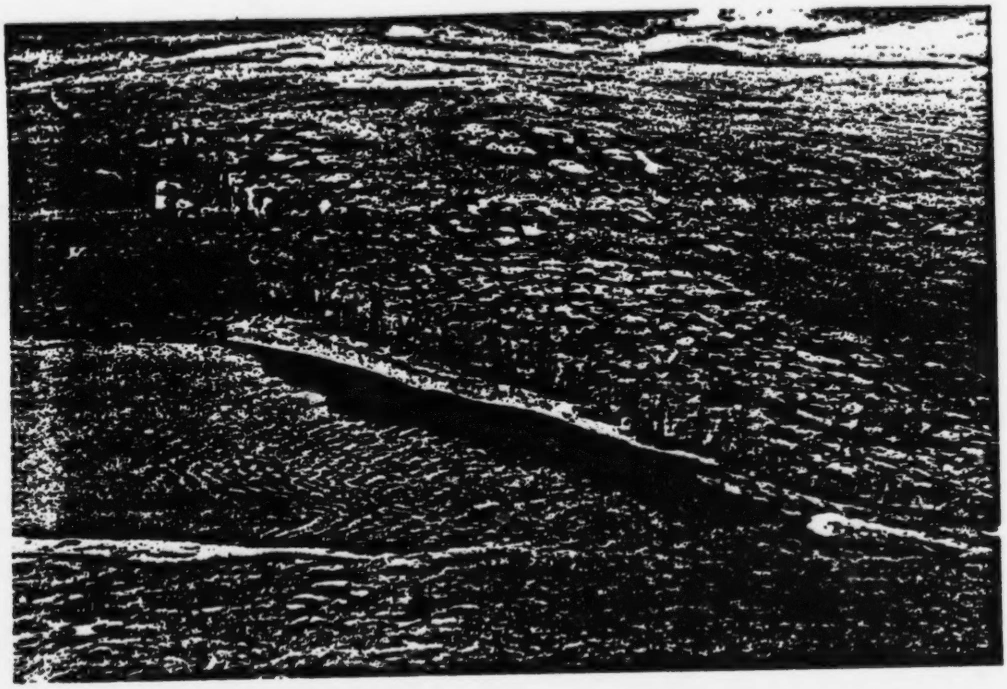


PHOTO 7 : Head of Bloody Falls. Meta sedimentary rock at river level and WSC gagehouse on left of photo.

PHOTO 8 : Lake above Bloody Falls looking west to left bank. Note stability of sandstone outcrops and shallow slope at neck of OSF.

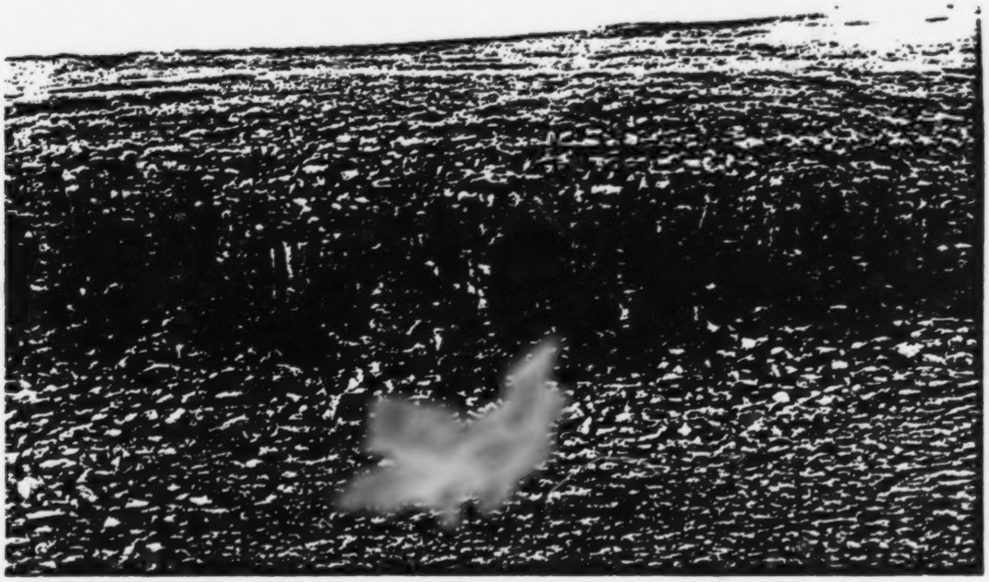


PHOTO 9 : Outcrop of igneous rock near left bank above falls. Note frost shattered debris typical of region. Fragments are 1-10 m^3 and good source of rip rap.

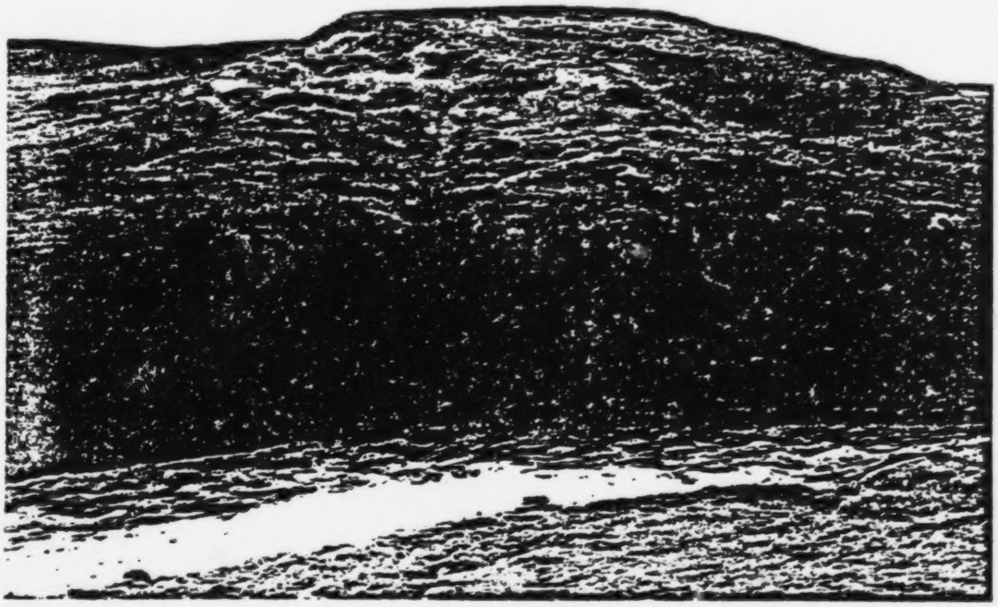


PHOTO 10 : Bloody Falls right bank. Note columnar jointing in igneous rock and minor overburden of sandy soil.

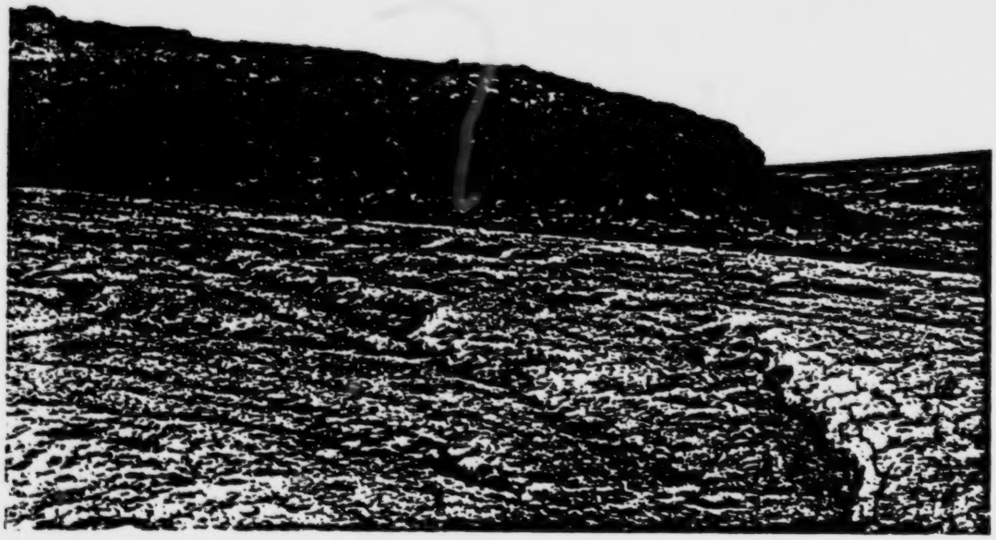


PHOTO 11: Lobe of silt flow from old slide feature on left bank of river upstream of Bloody Falls.

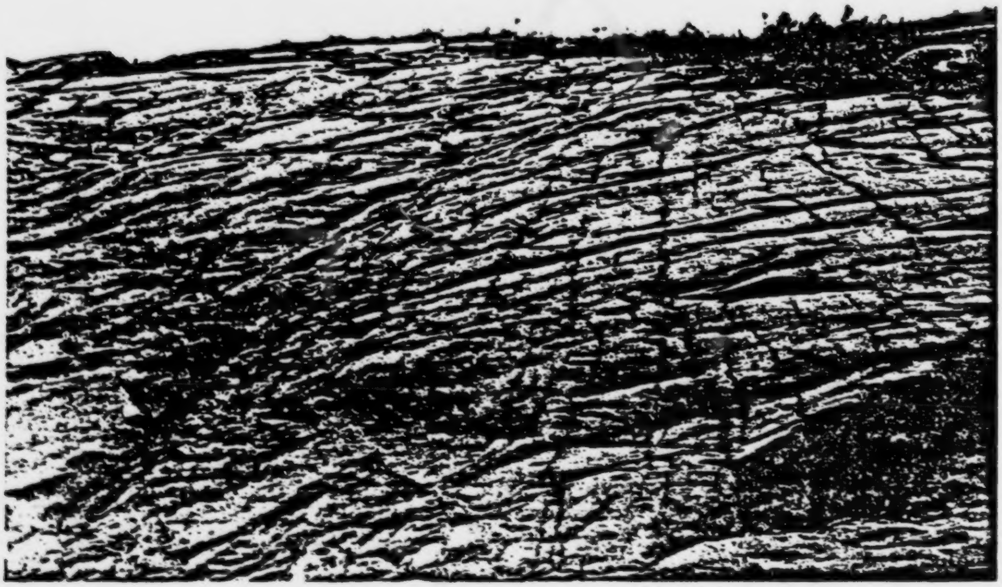
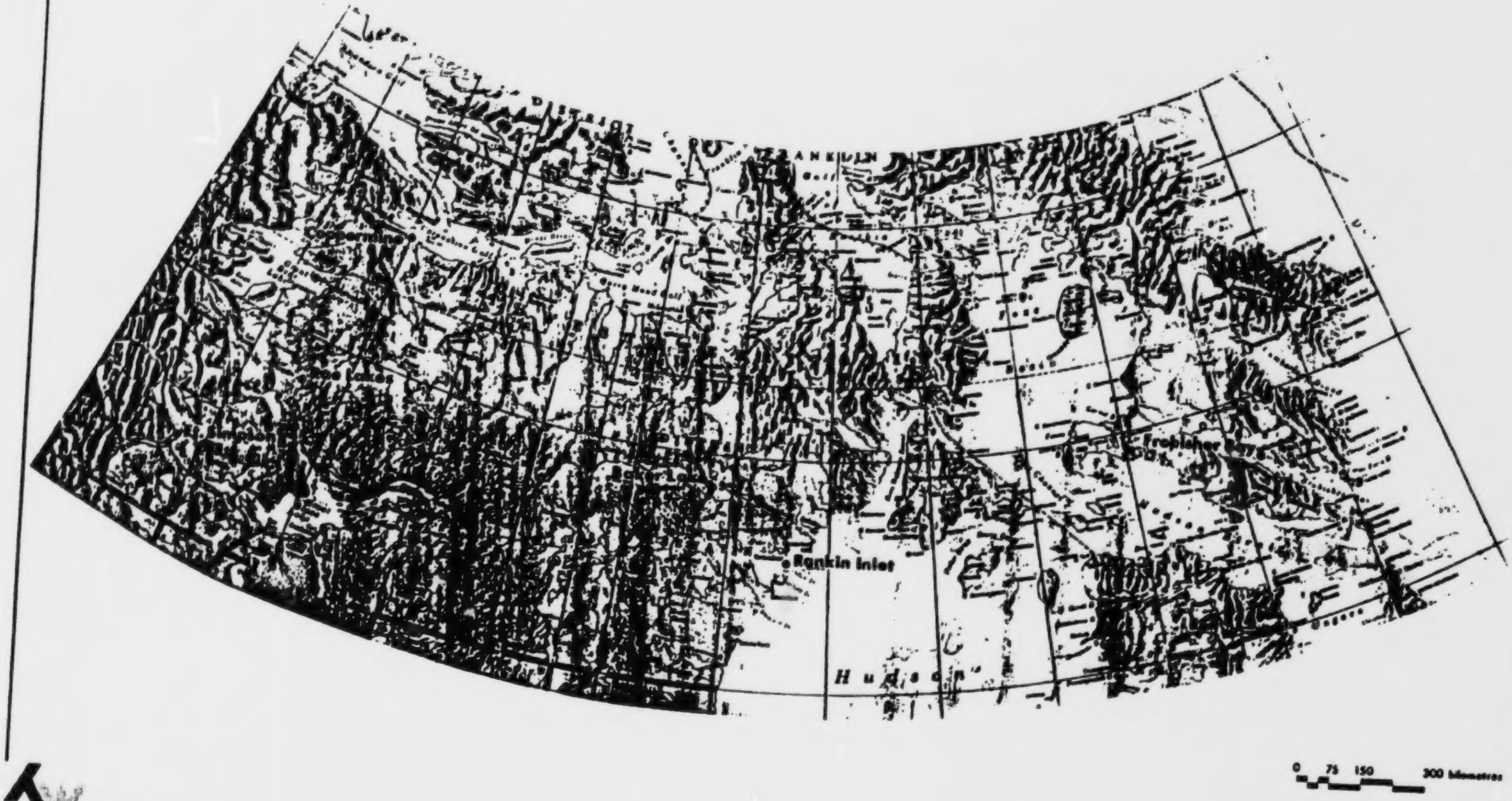


PHOTO 12 : Outcrop of gabbro at foot of Bloody Falls - left bank.

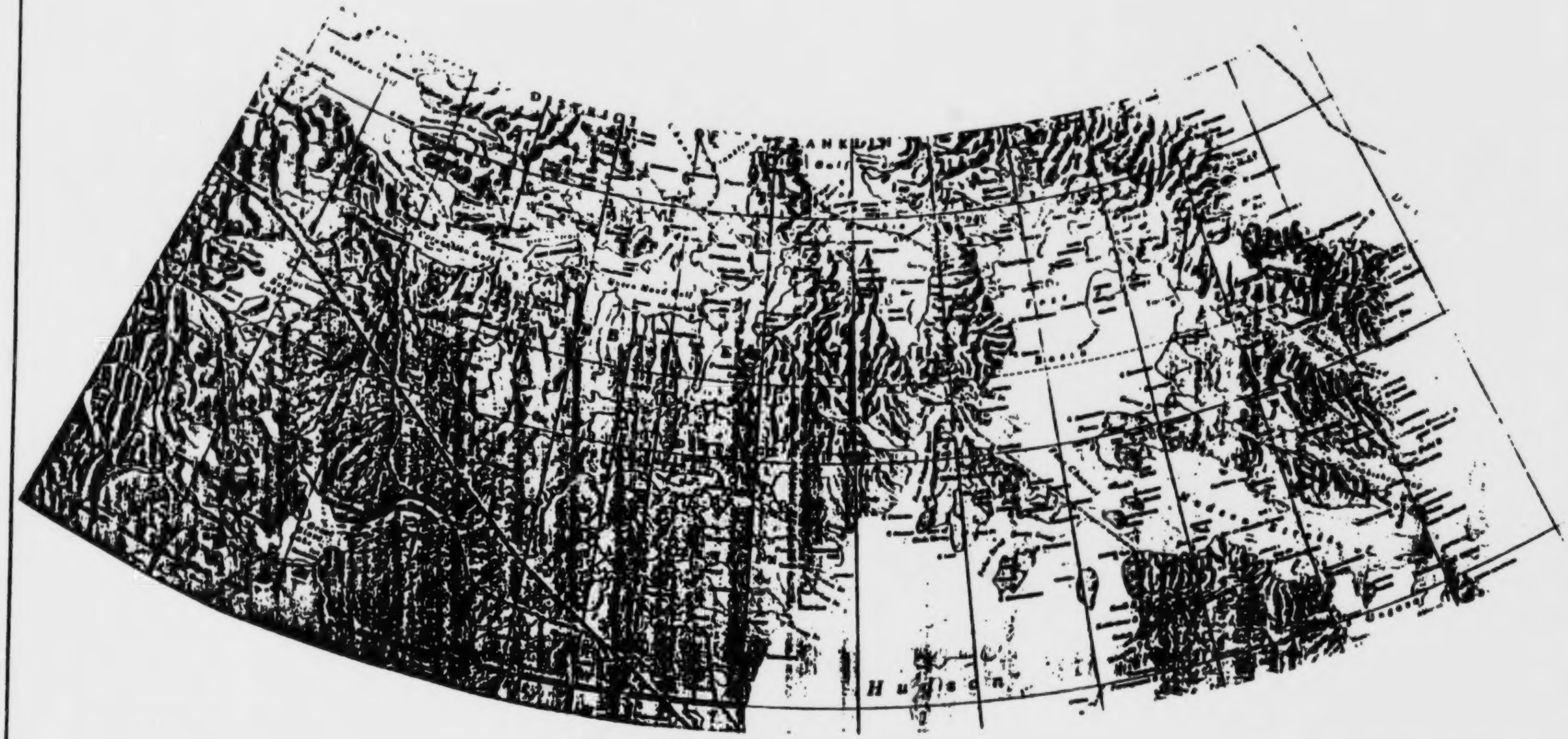
FIGURE 1.1


Rankin Inlet
Frobisher Bay
Hudson
0 75 150 300 kilometres

hydrowest consultants inc.

LOCATION OF STUDY AREAS

FIGURE 1.2


DISTRICT
Hudson
0 75 150 200 Kilometres

Source : N.W.T. Water Resource Study, Acres Ltd., 1976

LEGEND

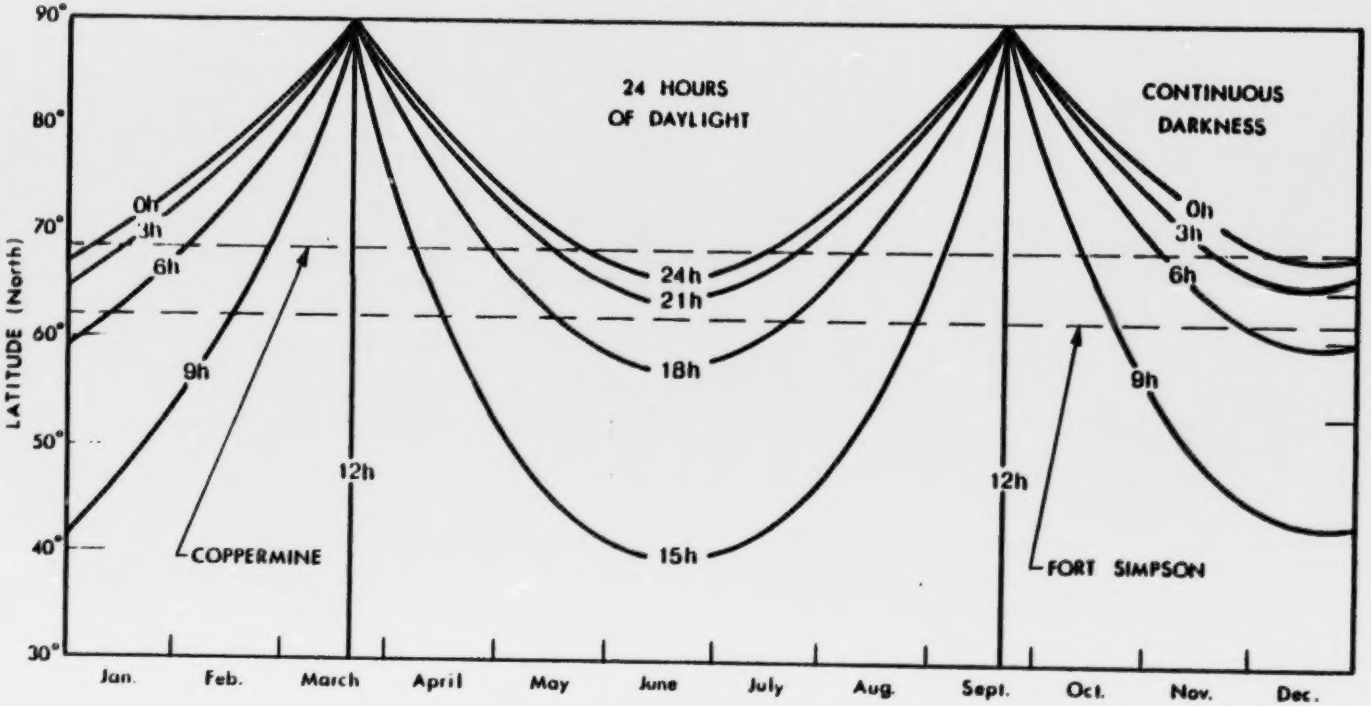
--- SOUTHERN LIMIT OF CONTINUOUS PERMAFROST ZONE

〰 NORTHERN LIMIT OF TREES

hydrowest consultants inc.

EXTENT OF
PERMAFROST ZONE AND TREE LINE

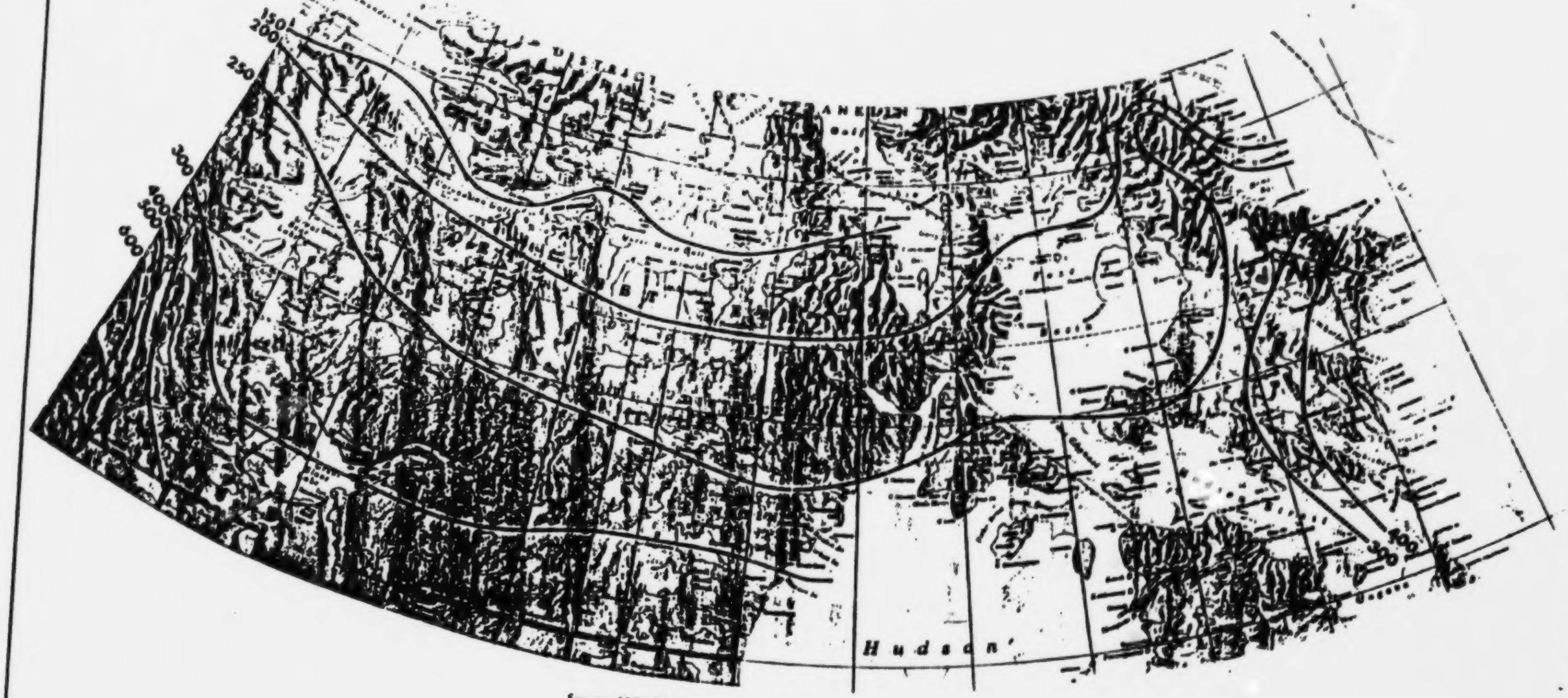
FIGURE 2.1



DURATION OF DAYLIGHT HOURS

NOTE
BAKER LAKE, FROBISHER BAY,
RAE LAKES AND RANKIN INLET
LIE BETWEEN THE LATITUDES
OF COPPERMINE AND FORT SIMPSON

FIGURE 2.2


150
200
250
300
400
500
600
DISTRICT
Hudson
400
300
0 75 150 300 kilometres

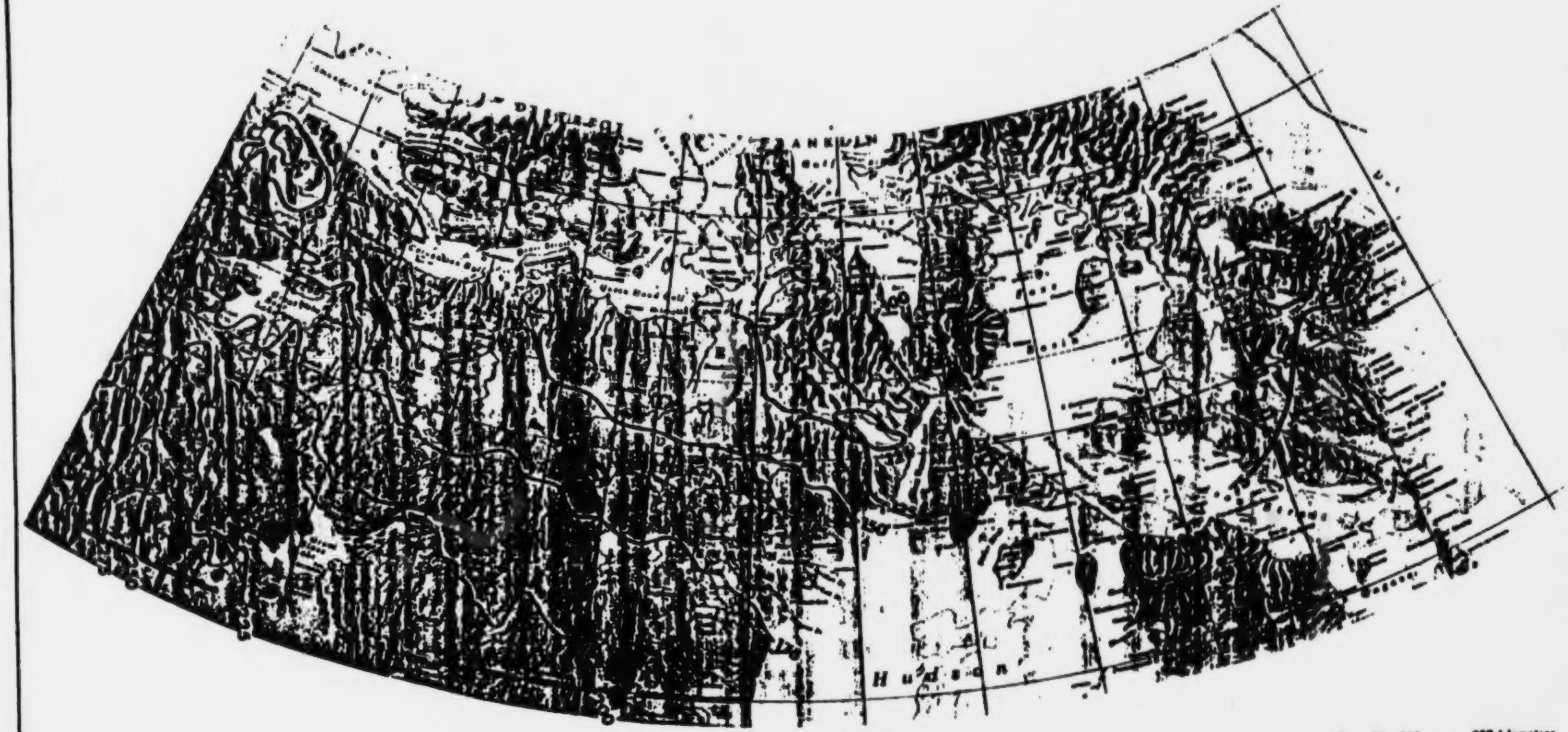
Source: N.W.T. Water Resource Study, Acres Ltd., 1976

NOTE: NUMBERS INDICATE mm/yr

REGIONAL ESTIMATE OF
MEAN ANNUAL PRECIPITATION

hydrowest consultants inc.

FIGURE 2.3


DISTRICT OF FRANKLIN
Hudson
150
0 75 150 300 kilometres

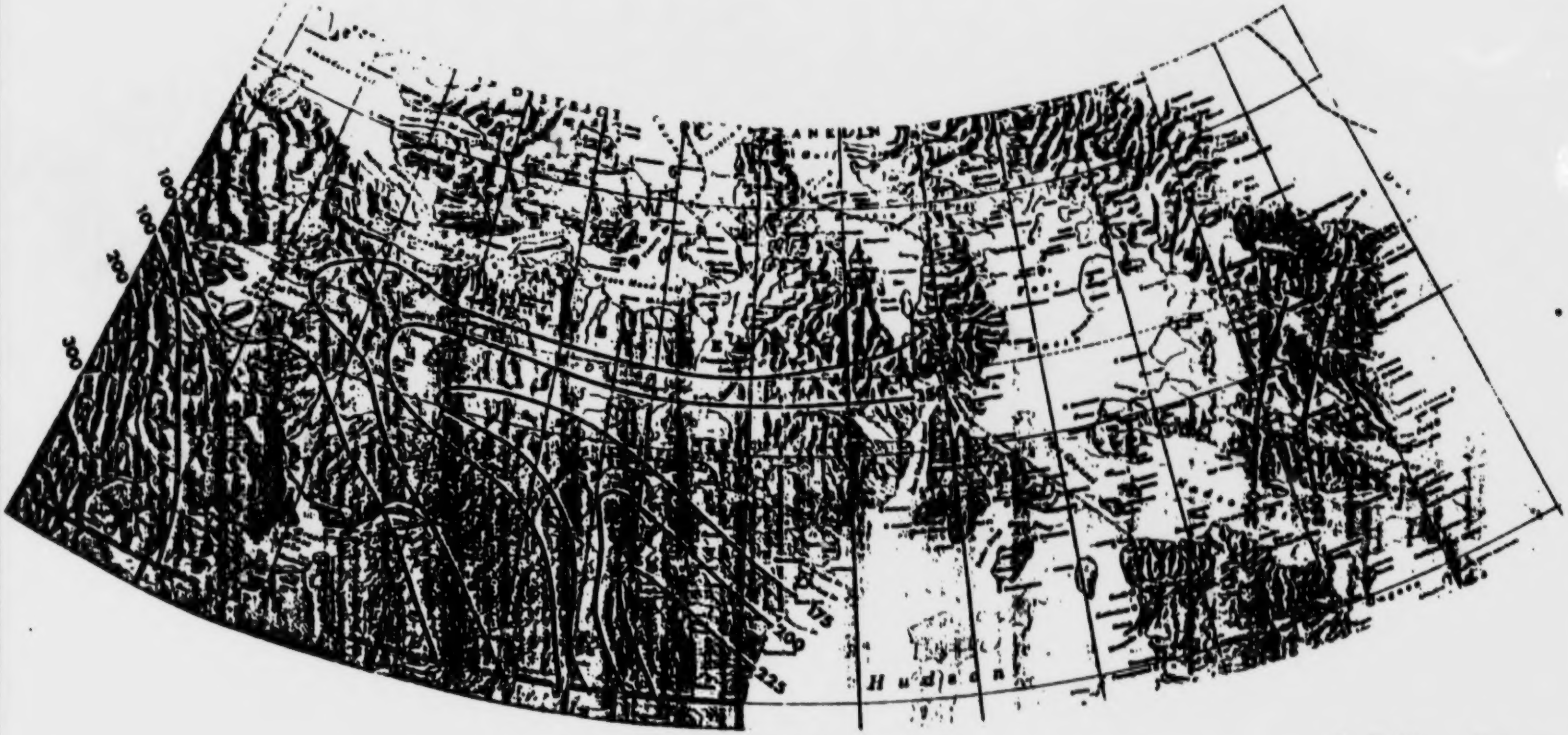
Source: N.W.T. Water Resources Inventory Study, Shawinigan Ltd., 1982

NOTE: NUMBERS INDICATE mm/yr

REGIONAL ESTIMATE OF
MEAN ANNUAL EVAPORATION

hydrowest consultants inc.

FIGURE 2.4


DISTRICT
FRANKLIN
Hudson
100
100
200
300
175
200
225
0 75 150 300 kilometres

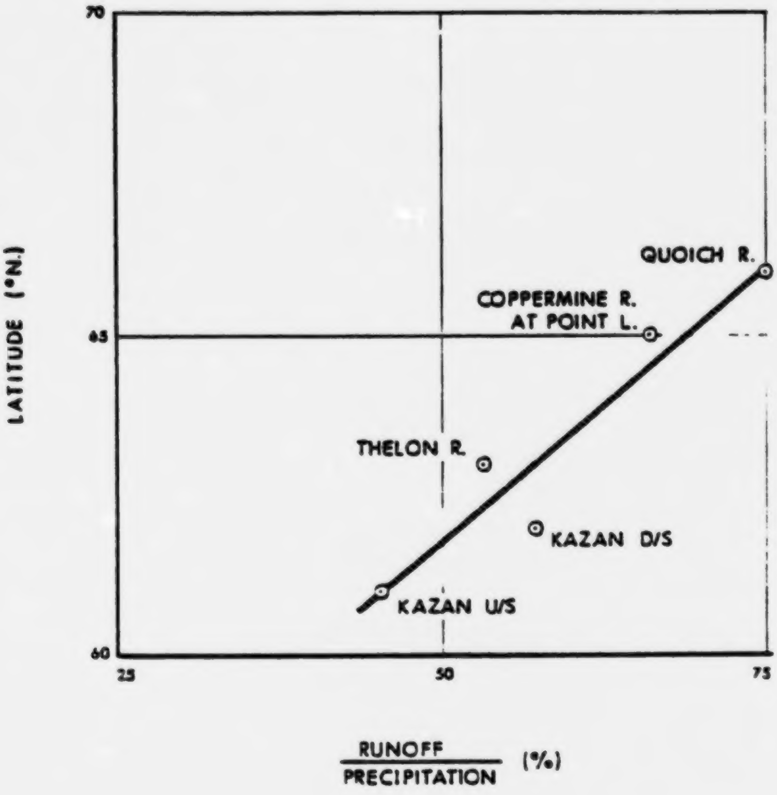
Source: N.W.T. Water Resource Study, Acres Ltd., 1976

NOTE: NUMBERS INDICATE mm/yr

REGIONAL ESTIMATE OF
MEAN ANNUAL RUNOFF

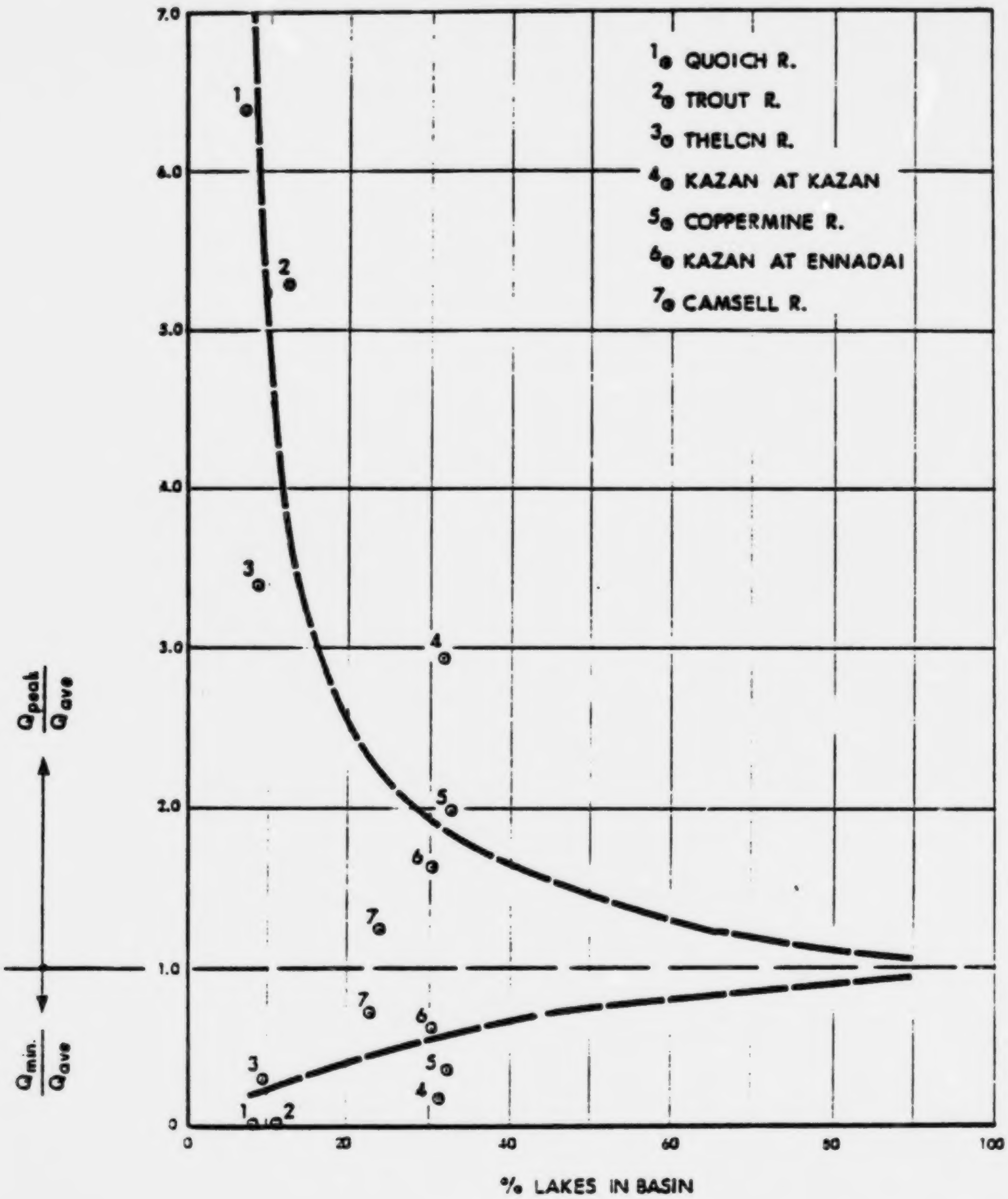
hydrowest consultants inc.

FIGURE 2.5



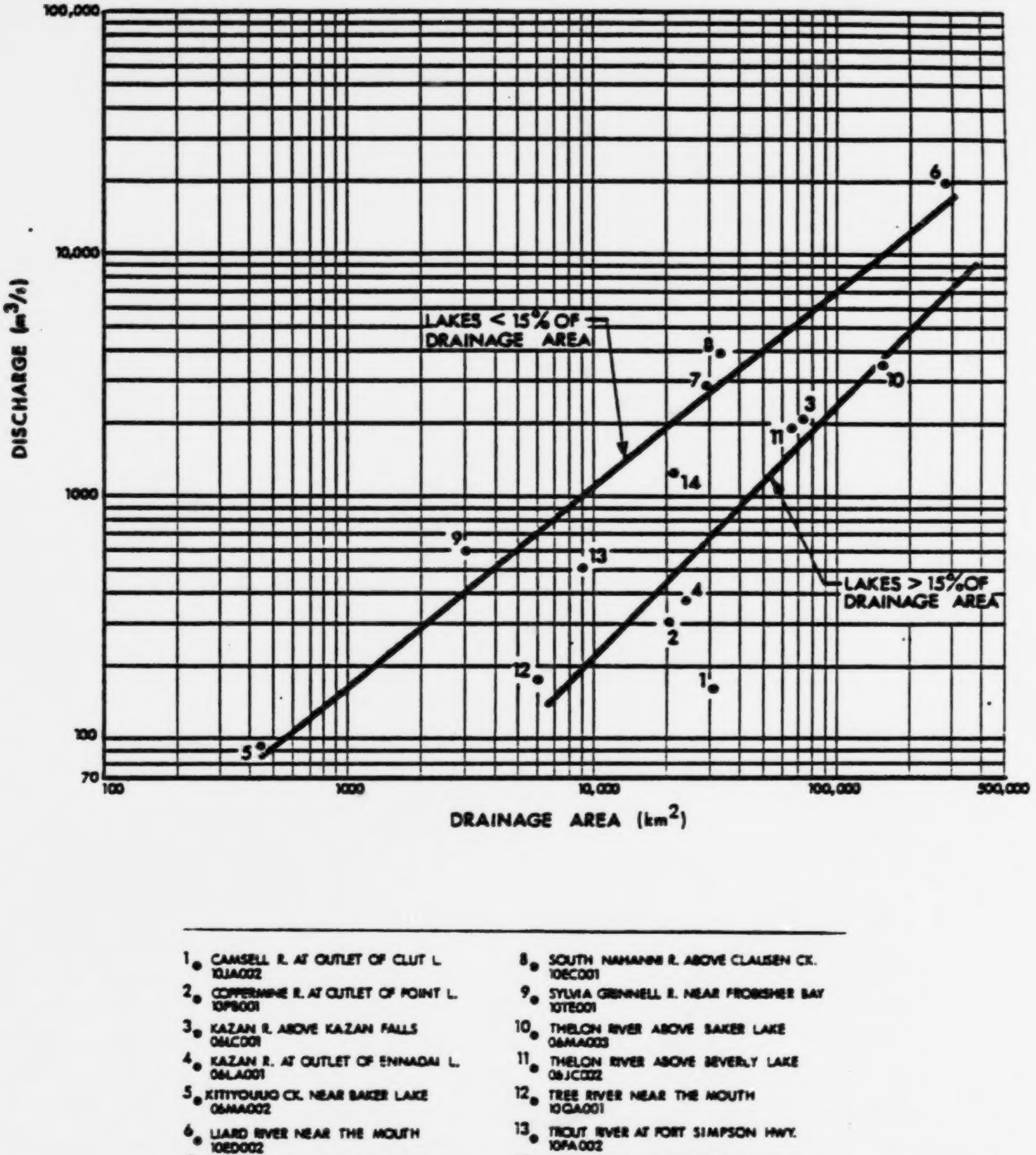
RELATIONSHIP BETWEEN RUNOFF COEFFICIENT AND LATITUDE OF CENTRE OF BASIN

FIGURE 2.6



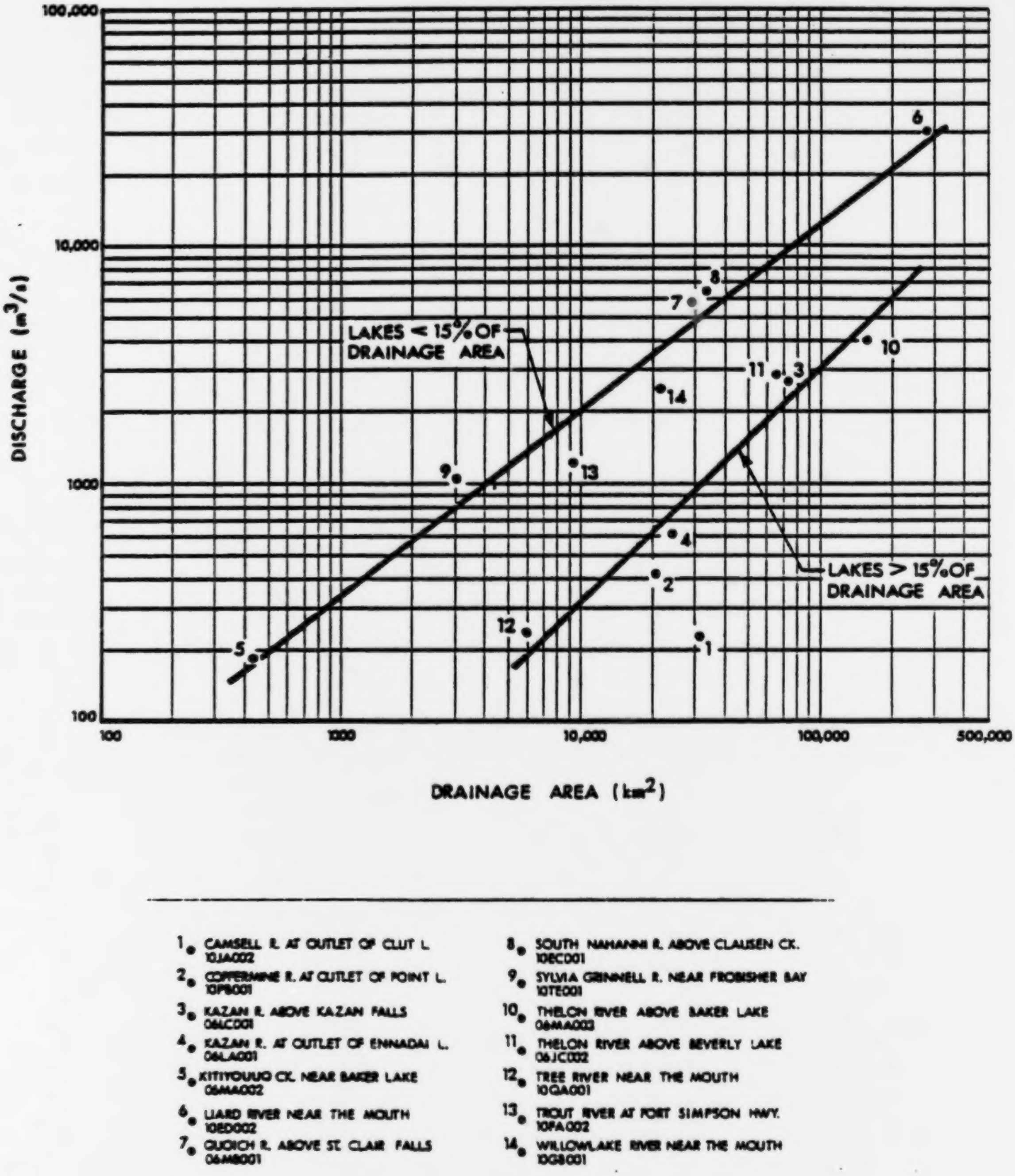
RELATIONSHIP BETWEEN
PROPORTION OF LAKES IN BASIN
AND MAXIMUM PEAK
AND MINIMUN FLOW RATIOS

FIGURE 2.7



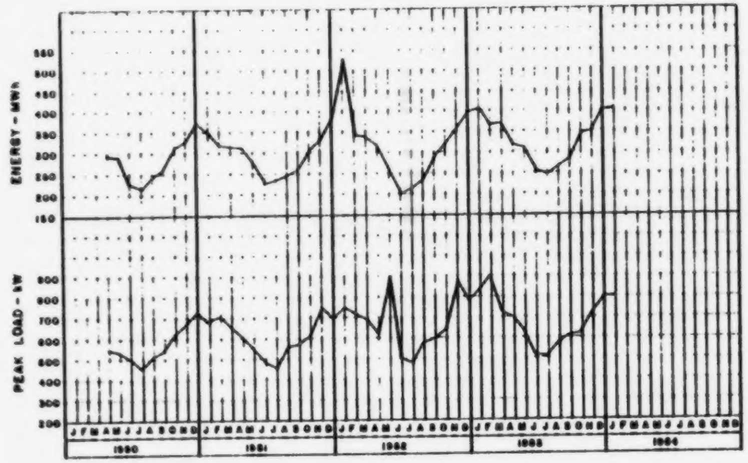
1: 20 YEAR FLOODS

FIGURE 2.8

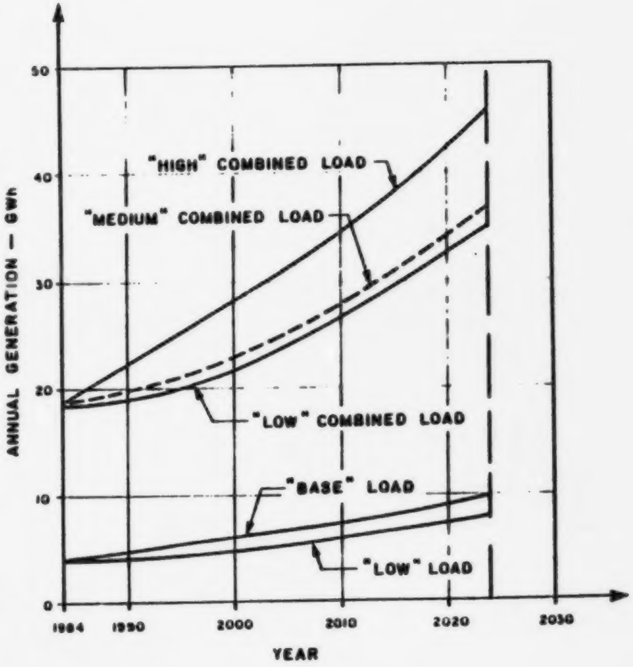


1: 1000 YEAR FLOODS

FIGURE 3.1



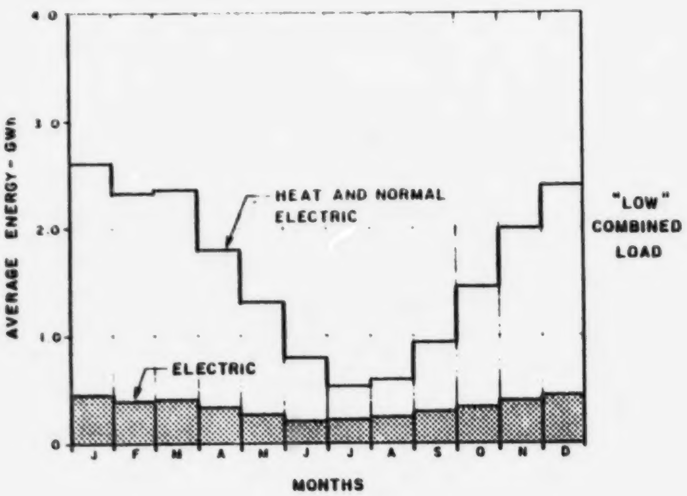
- HISTORICAL PLANT LOAD -

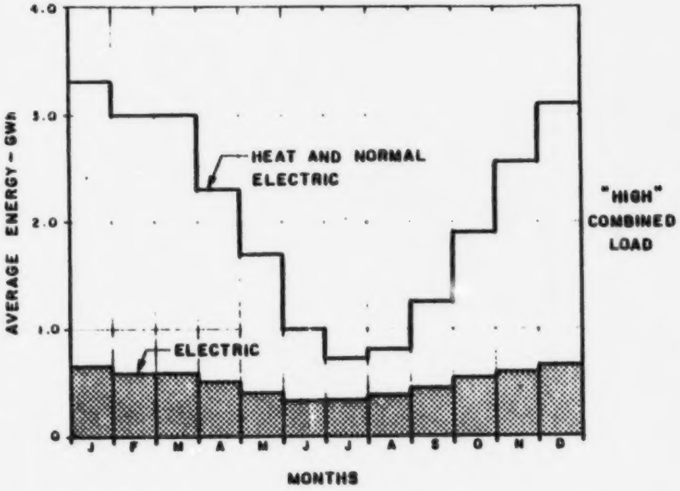


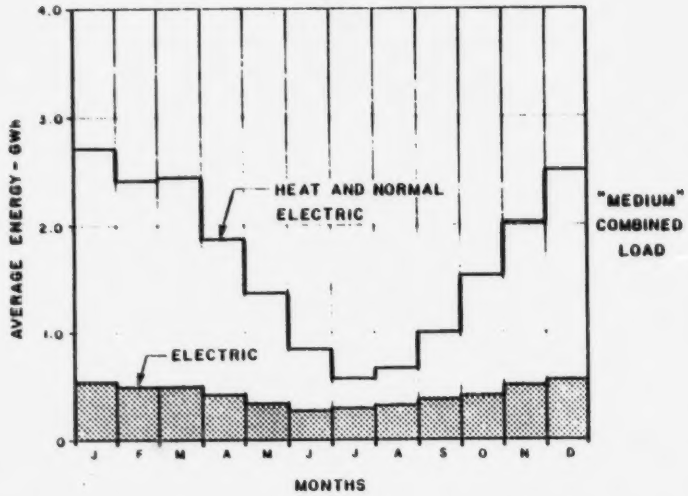
- LOAD FORECAST -

BAKER LAKE DEVELOPMENT

FIGURE 3.2

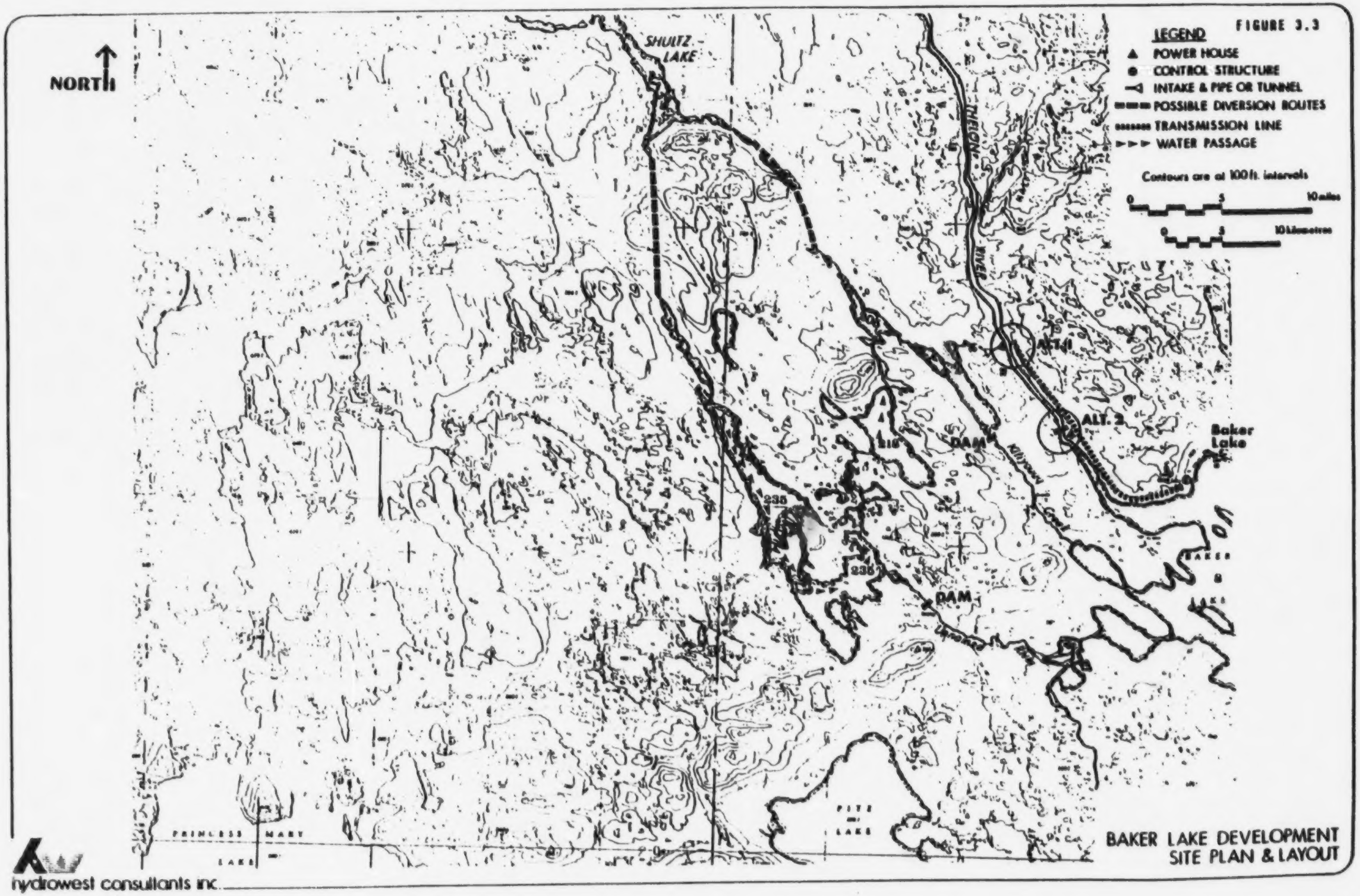






BAKER LAKE DEVELOPMENT
MONTHLY LOADS, 1994

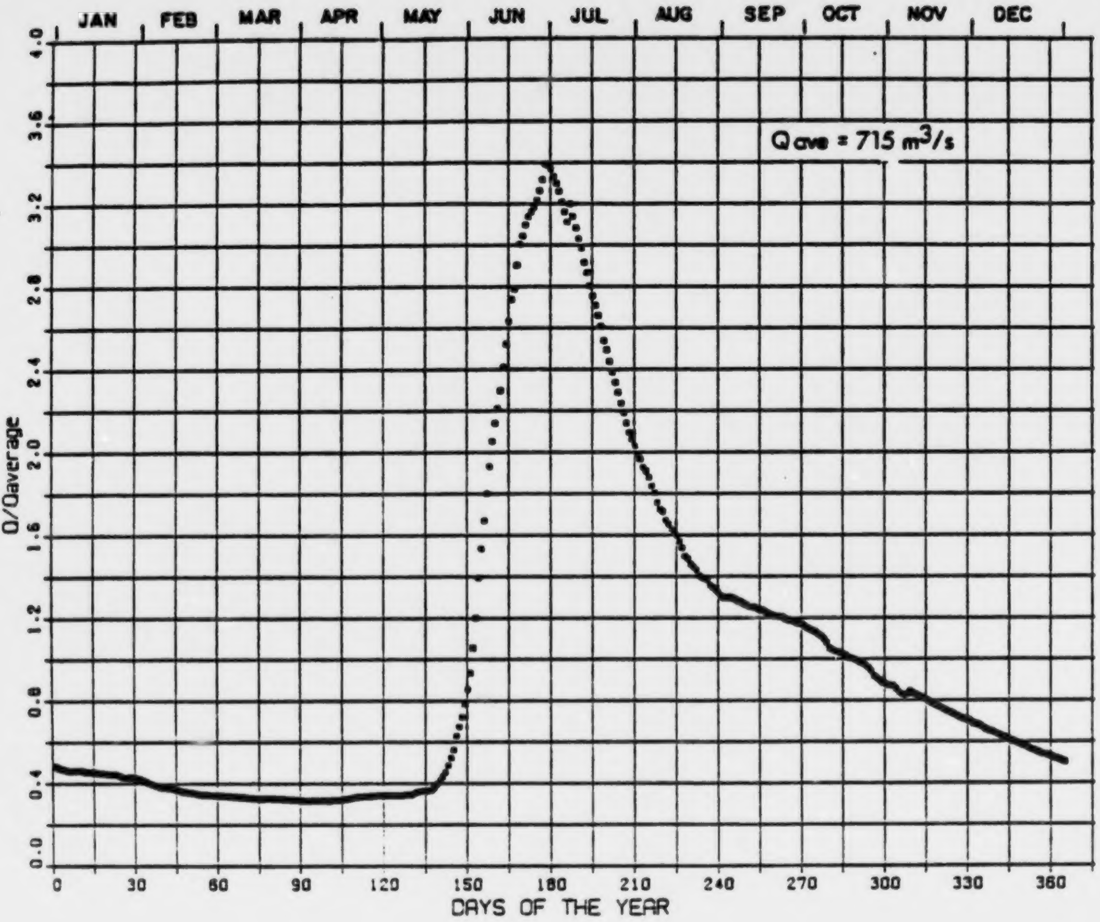
FIGURE 3.3


LEGEND
▲ POWER HOUSE
● CONTROL STRUCTURE
INTAKE & PIPE OR TUNNEL
POSSIBLE DIVERSION ROUTES
TRANSMISSION LINE
►►► WATER PASSAGE
Contours are at 100 ft. intervals
0
5
10 miles
0
5
10 kilometres
NORTH
SHULTZ LAKE
THELON RIVER
ALT. 1
ALT. 2
Baker Lake
DAM
DAM
235
235
BAKER LAKE
PITZ LAKE
PRINCESS MARY LAKE

BAKER LAKE DEVELOPMENT
SITE PLAN & LAYOUT

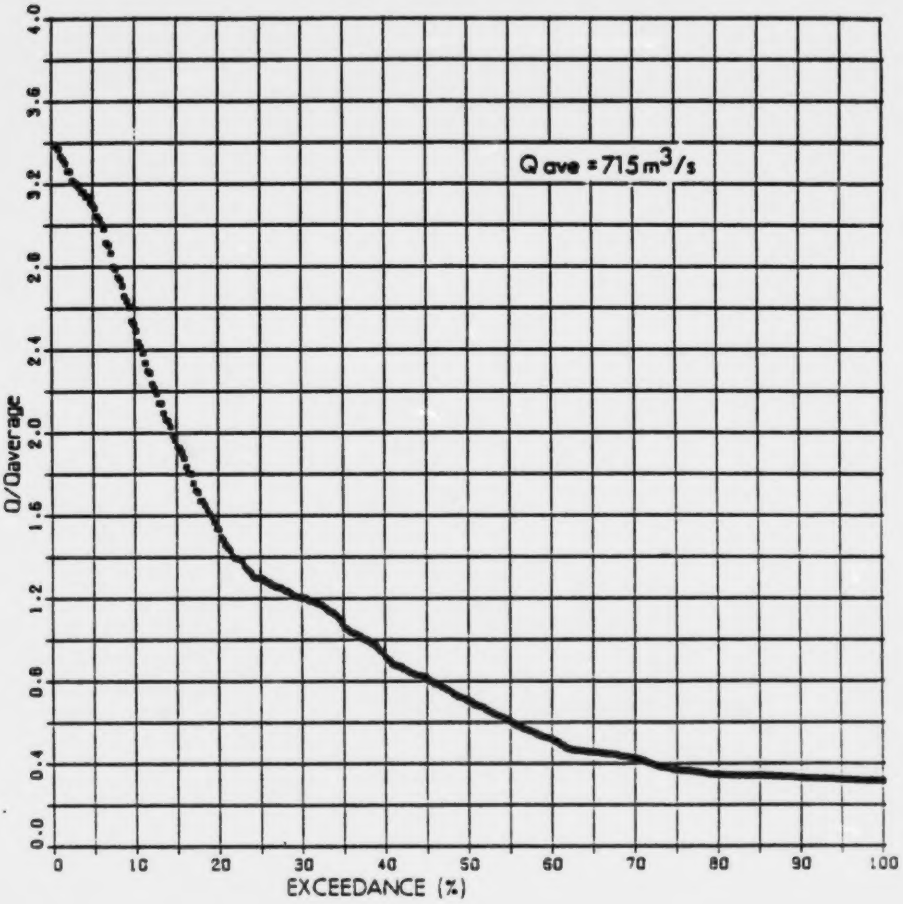
hydrowest consultants inc.

FIGURE 3.4



AVERAGE
DIMENSIONLESS DAILY FLOWS
THELON RIVER AT BAKER LAKE

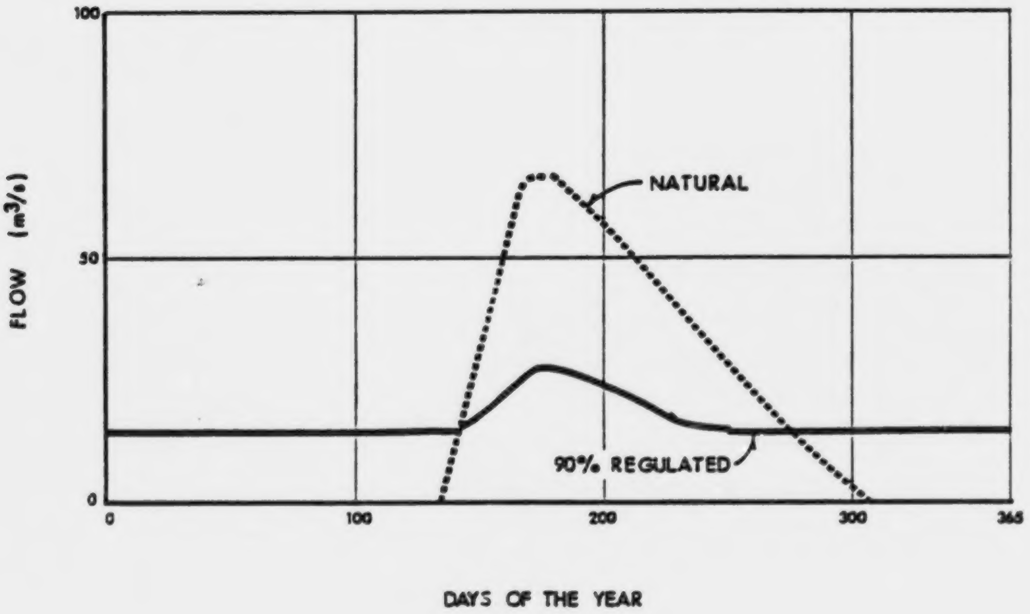
FIGURE 3.5



$Q_{MINIMUM}$ = 225 ³/s

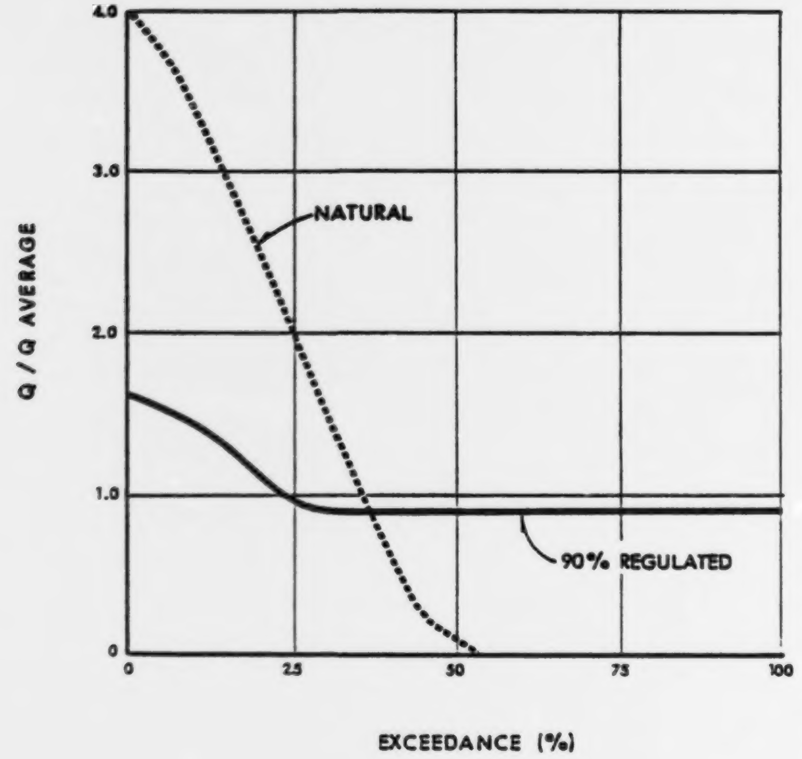
DIMENSIONLESS
DAILY FLOW DURATION CURVE
THELON RIVER AT BAKER LAKE

FIGURE 3.6



AVERAGE DAILY FLOWS
KITI`'OUUQ CREEK & UNNAMED RIVER
NEAR BAKER LAKE

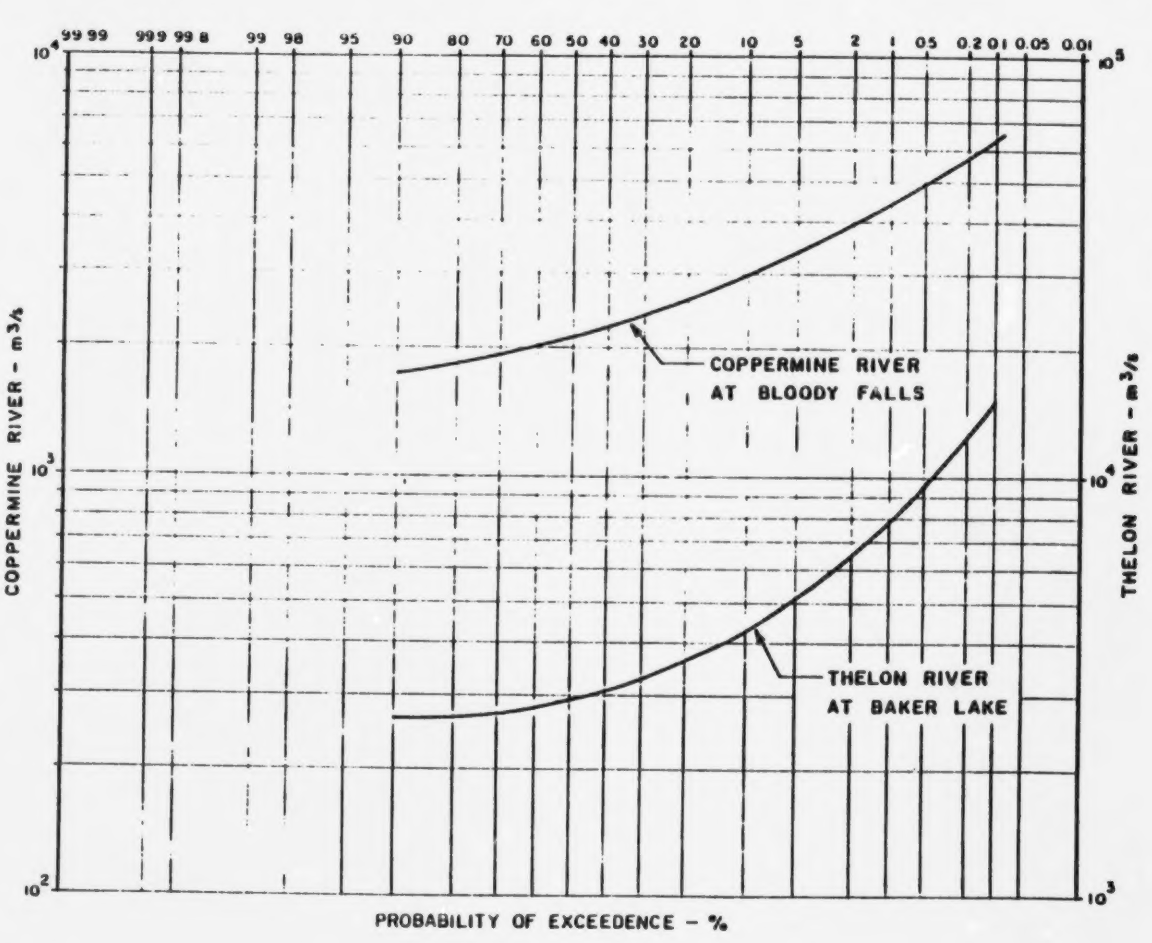
FIGURE 3.7



$Q_{av} = 16.95\ m^3/s$

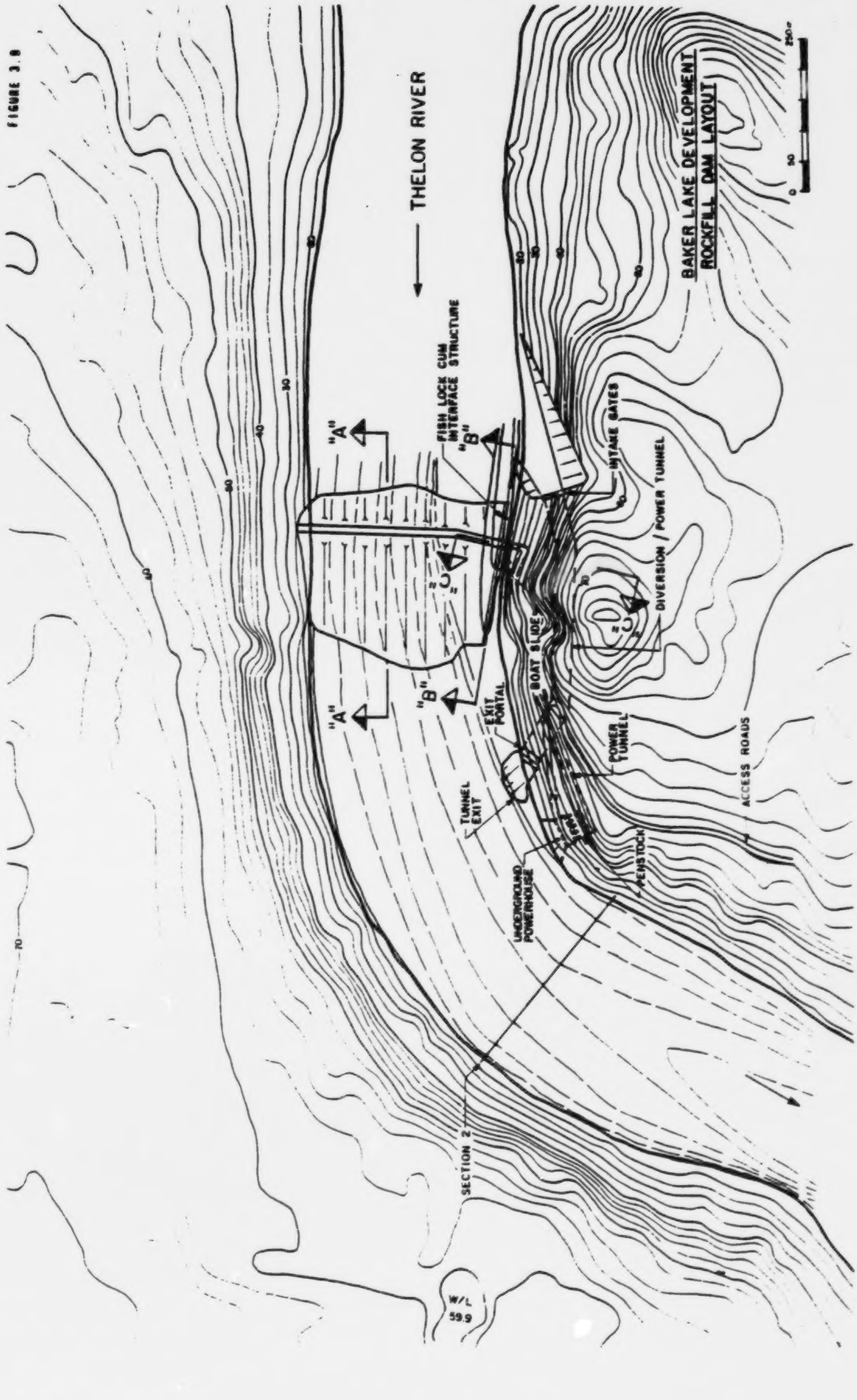
DIMENSIONLESS
DAILY FLOW DURATION CURVE
KITIYOUUQ CREEK & UNNAMED RIVER
NEAR BAKER LAKE

FIGURE 3.8



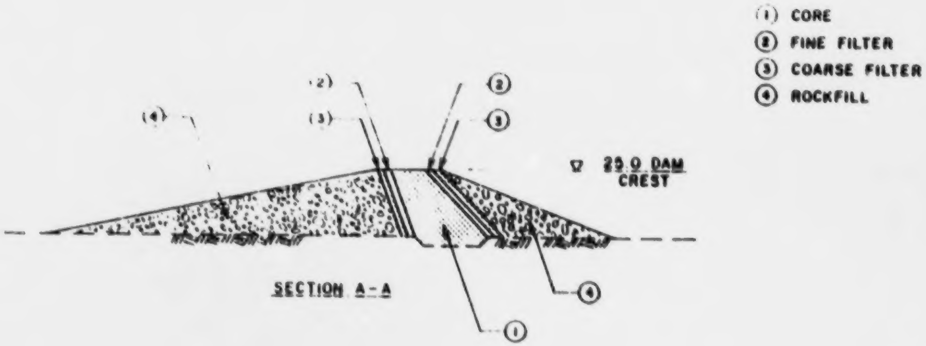
DESIGN FLOODS

FIGURE 3.8

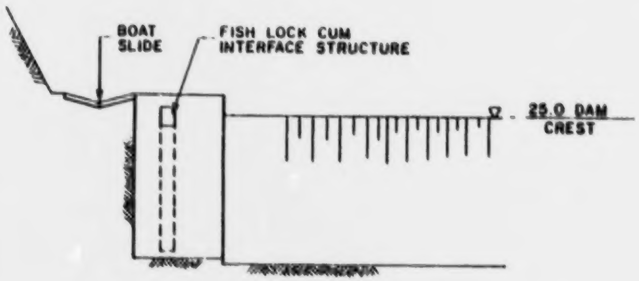

THELON RIVER
"A"
"B"
"C"
"D"
FISH LOCK CUM INTERFACE STRUCTURE
INTAKE GATES
DIVERSION / POWER TUNNEL
BOAT SLIDE
EXIT PORTAL
POWER TUNNEL
ACCESS ROADS
TUNNEL EXIT
UNDERGROUND POWERHOUSE
PENSTOCK
SECTION 2
W/L 59.9
70
60
50
40
30
0 50 250m

BAKER LAKE DEVELOPMENT
ROCKFILL DAM LAYOUT

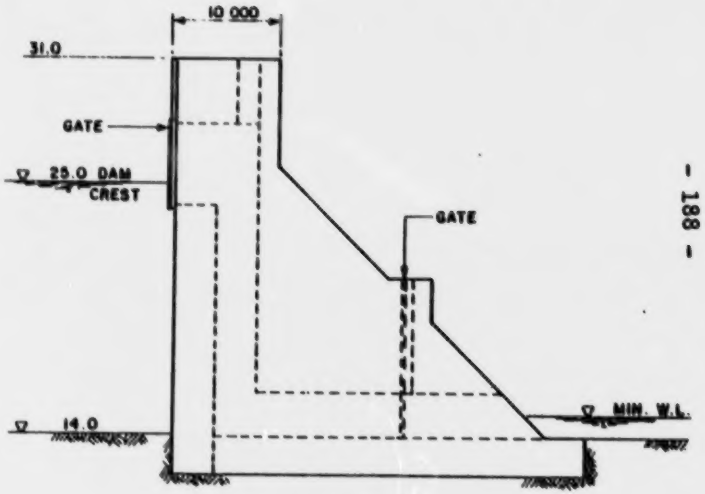
FIGURE 3.10


(1) CORE
(2) FINE FILTER
(3) COARSE FILTER
(4) ROCKFILL
(4)
(2)
(3)
(2)
(3)
25.0 DAM CREST
(4)
(1)

SECTION A-A


BOAT SLIDE
FISH LOCK CUM INTERFACE STRUCTURE
25.0 DAM CREST

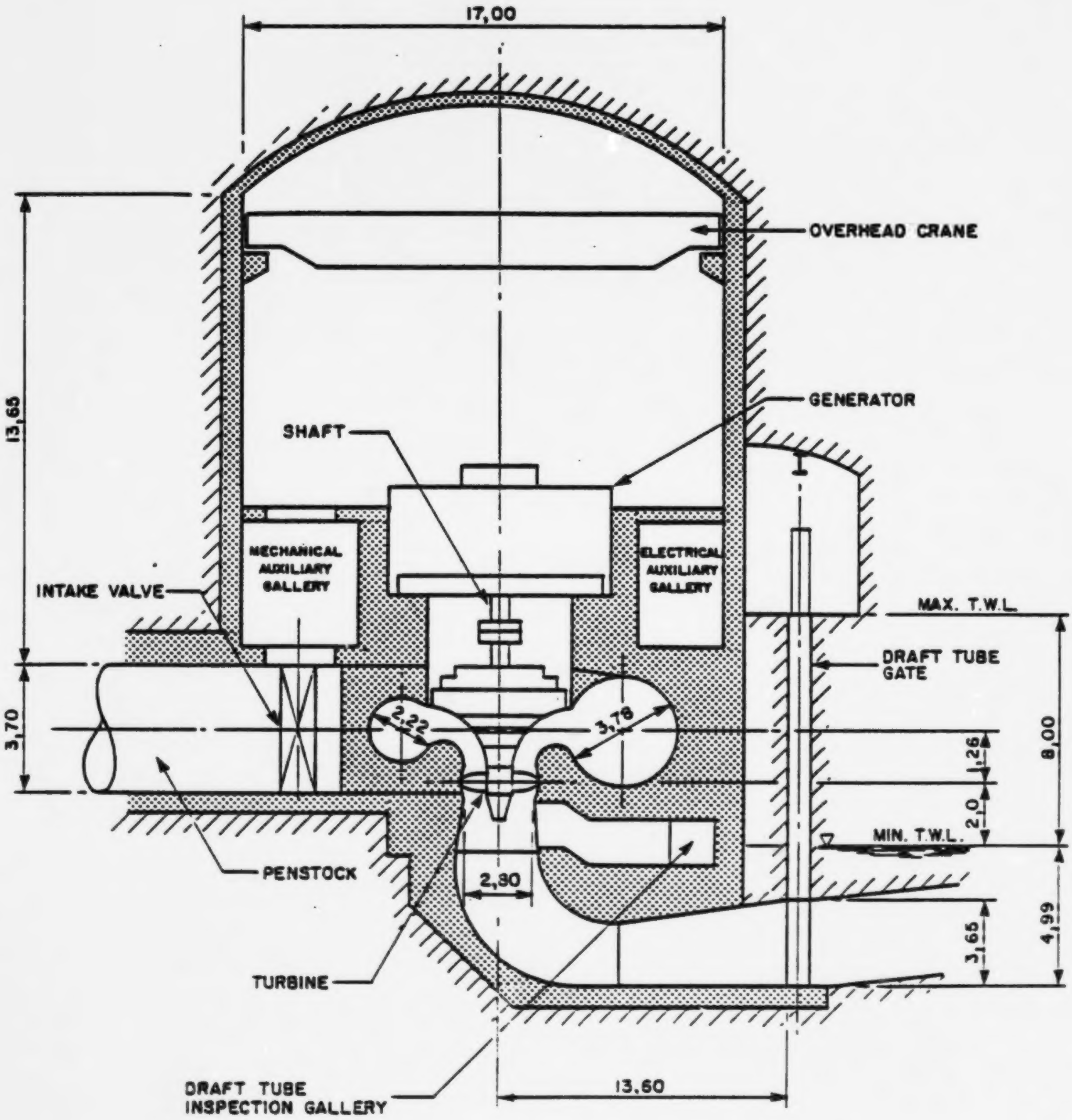
PARTIAL SECTION C-C
FISH LOCK CUM INTERFACE STRUCTURE


10 000
31.0
GATE
25.0 DAM CREST
GATE
14.0
MIN. W.L.

SECTION B-B
FISH LOCK

BAKER LAKE DEVELOPMENT
SECTIONS OF STRUCTURES

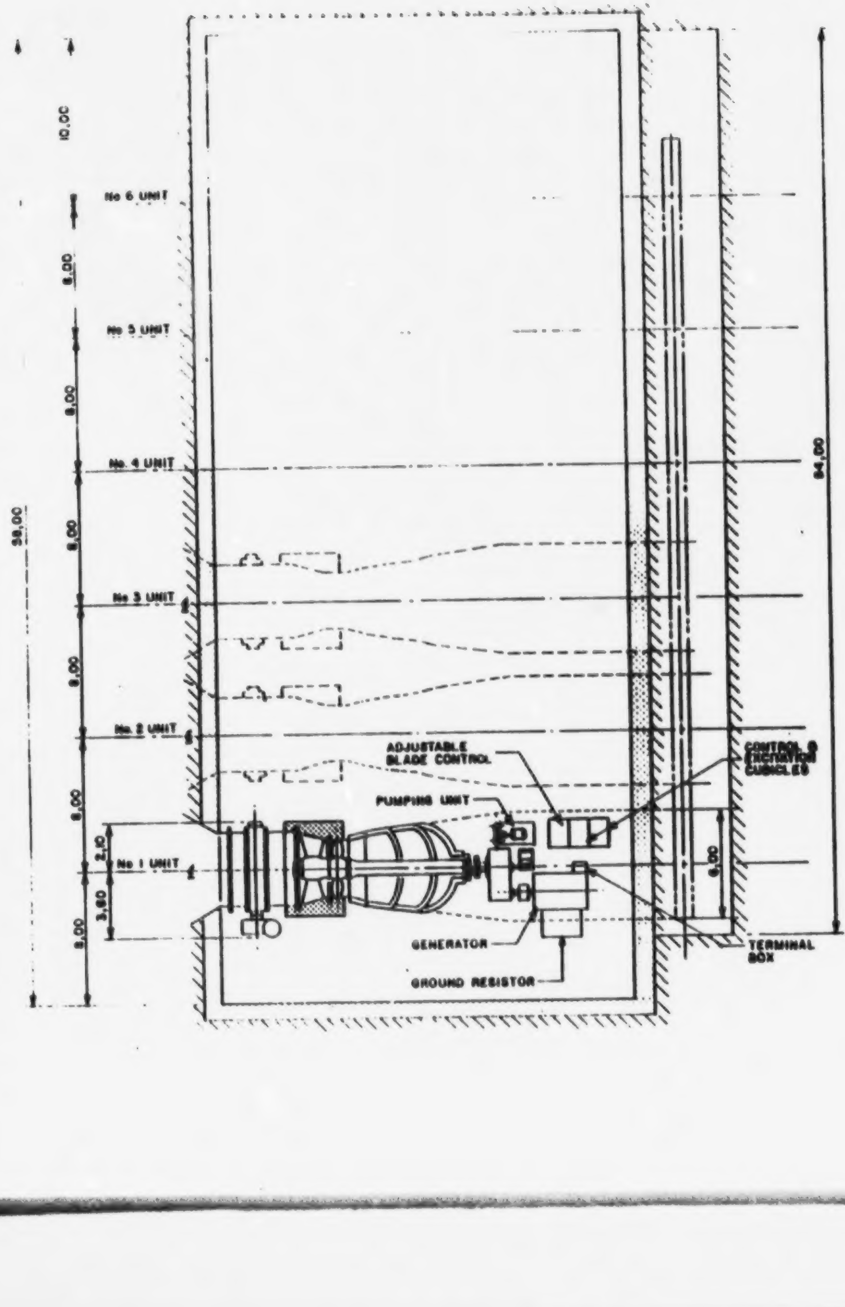
FIGURE 3.11

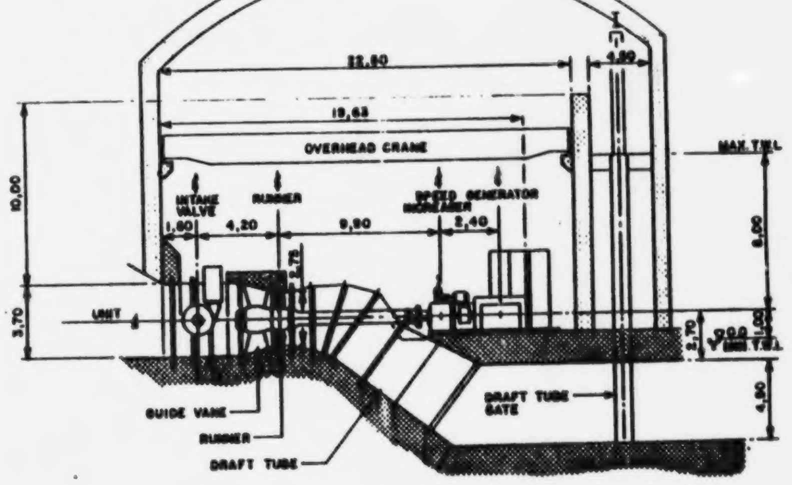

17,00
OVERHEAD CRANE
13,65
GENERATOR
SHAFT
MECHANICAL AUXILIARY GALLERY
ELECTRICAL AUXILIARY GALLERY
INTAKE VALVE
MAX. T.W.L.
DRAFT TUBE GATE
3,70
2,22
3,78
1,26
8,00
2,0
MIN. T.W.L.
PENSTOCK
2,30
3,65
4,99
TURBINE
DRAFT TUBE INSPECTION GALLERY
13,60

NOT TO SCALE

BAKER LAKE DEVELOPMENT
LAYOUT OF POWER STATION
KAPLAN UNITS

FIGURE 3.12

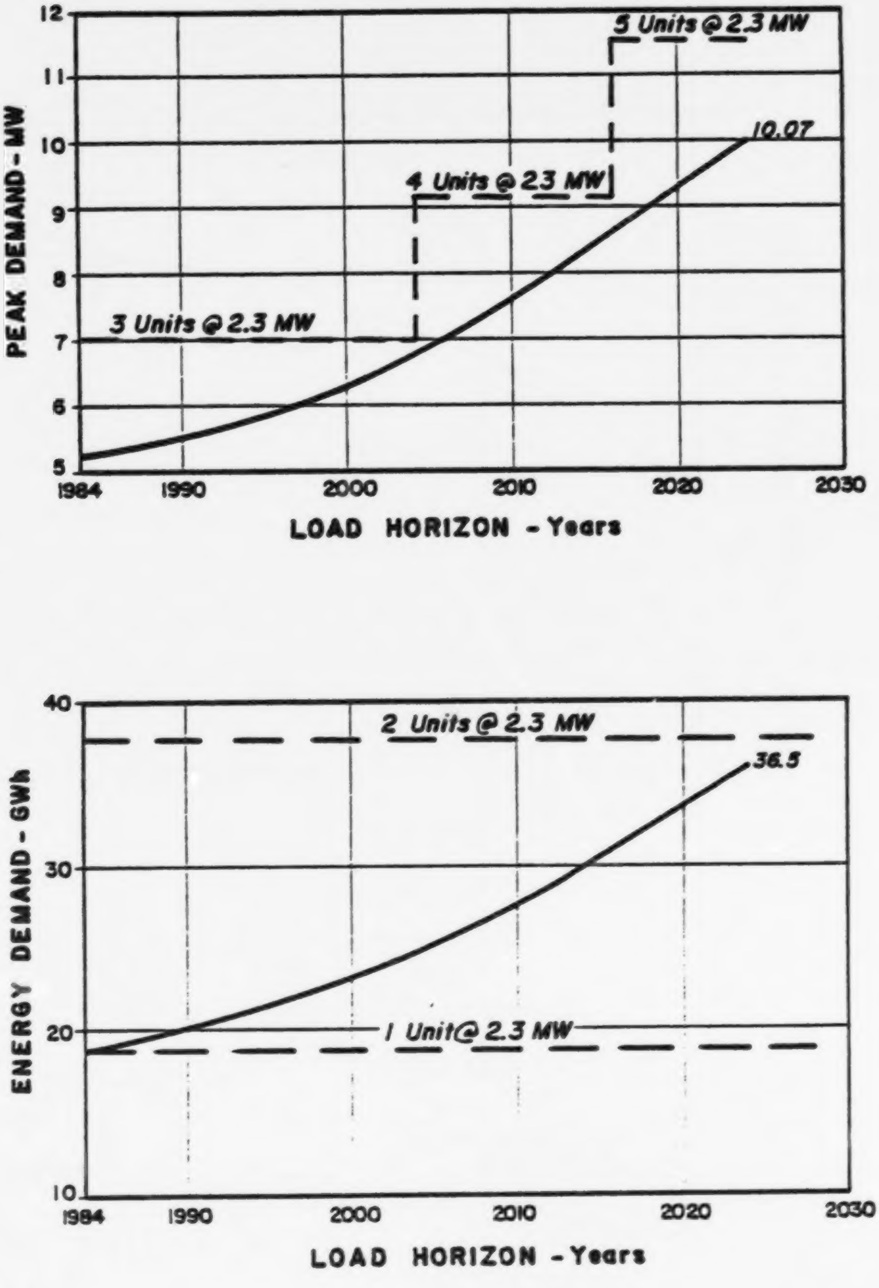

10,00
No 6 UNIT
8,00
No 5 UNIT
8,00
No 4 UNIT
38,00
8,00
No 3 UNIT
8,00
No 2 UNIT
8,00
2,10
No 1 UNIT
3,60
8,00
84,00
6,00
ADJUSTABLE BLADE CONTROL
PUMPING UNIT
CONTROL & EXCITATION CUBICLES
GENERATOR
GROUND RESISTOR
TERMINAL BOX


22,80
4,80
19,63
OVERHEAD CRANE
MAX.T.W.L.
INTAKE VALVE
RUNNER
SPEED INCREASER
GENERATOR
10,00
1,80
4,20
9,90
2,40
2,75
8,00
UNIT
3,70
1,00
2,70
MIN.T.W.L.
GUIDE VANE
RUNNER
DRAFT TUBE
DRAFT TUBE GATE
4,80

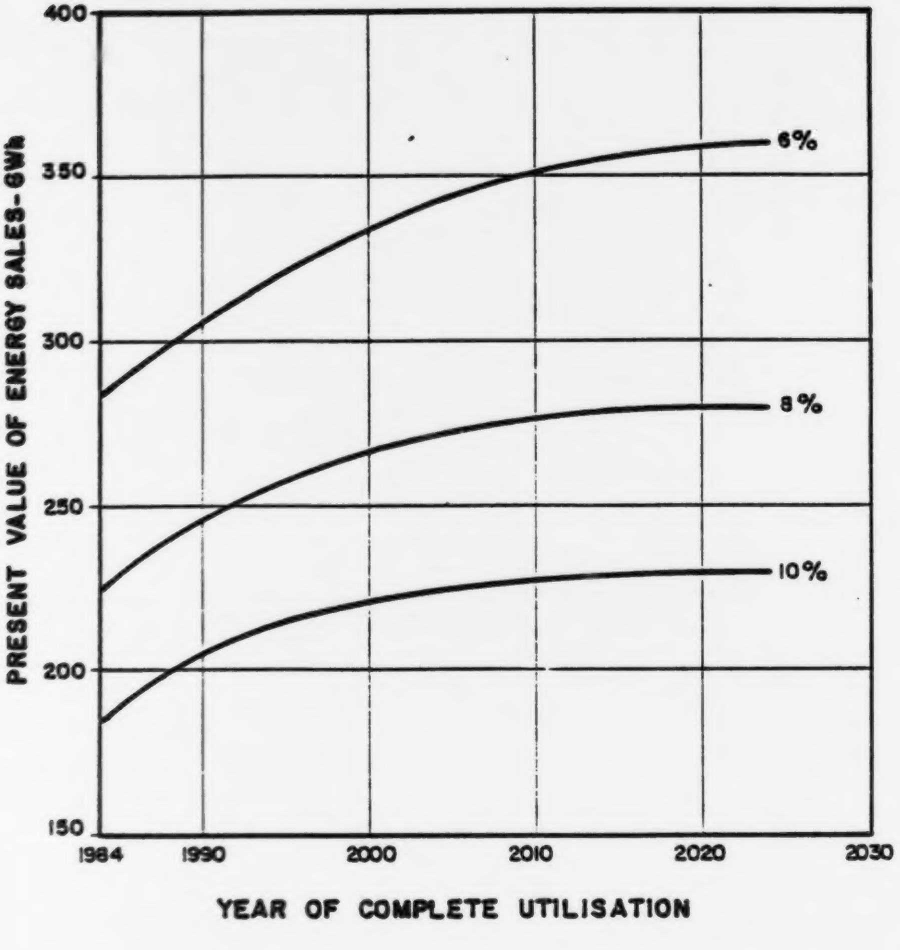
NOT TO SCALE

BAKER LAKE DEVELOPMENT
LAYOUT OF POWER STATION
HORIZONTAL TUBE TURBINE UNITS

FIGURE 3.13

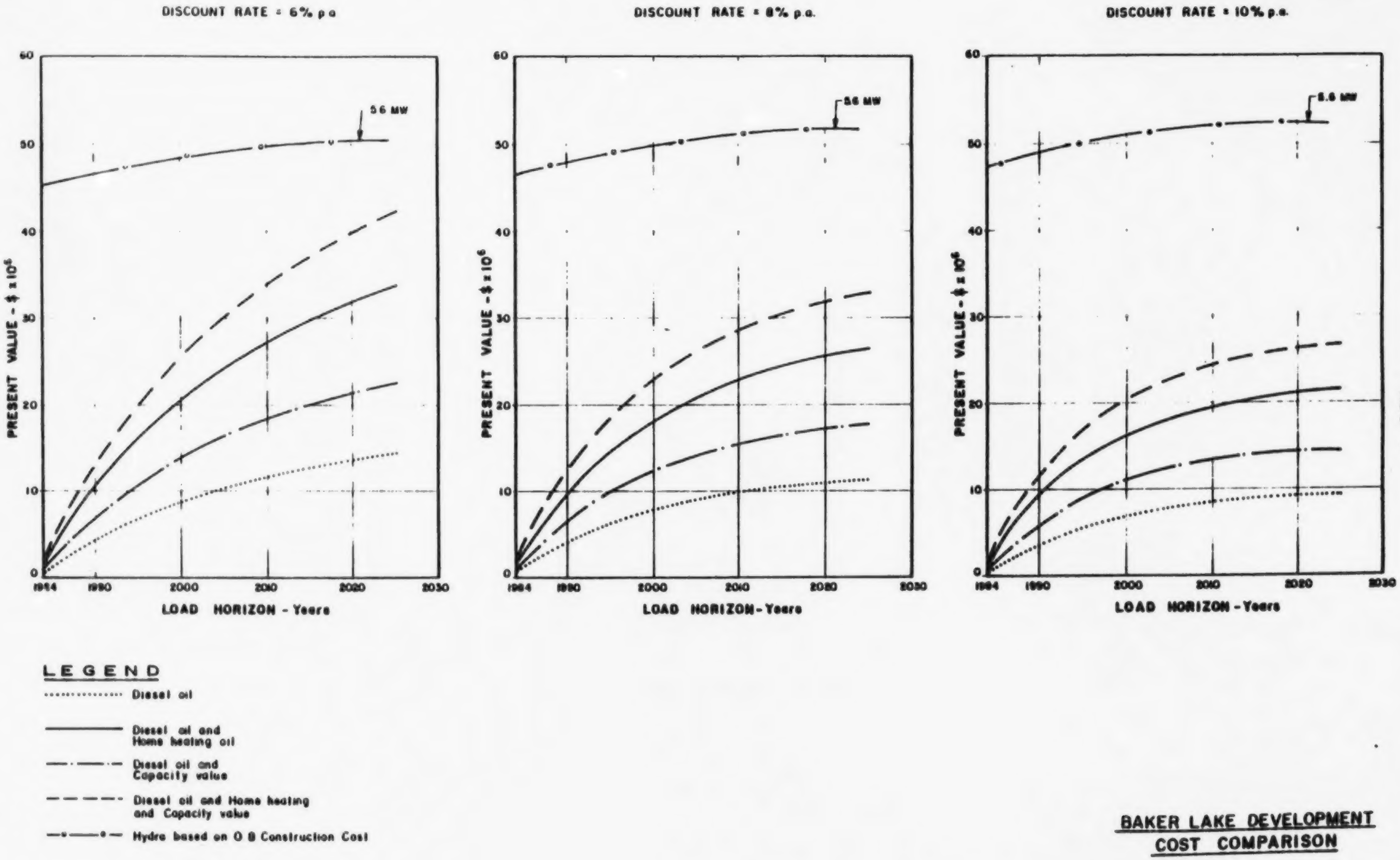


BAKER LAKE DEVELOPMENT
INSTALLATION vs DEMAND



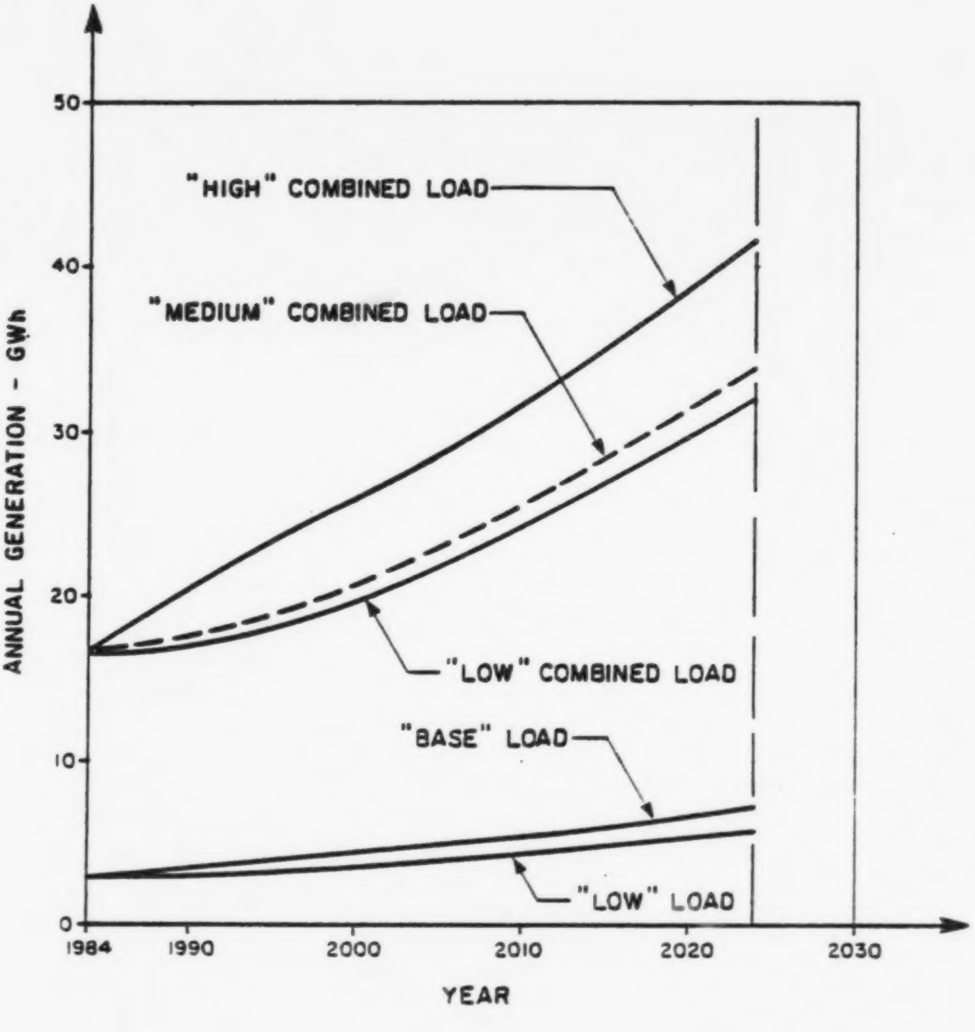
BAKER LAKE DEVELOPMENT
PRESENT VALUE OF ENERGY SALES
MEDIUM COMBINED LOAD

FIGURE 3.15



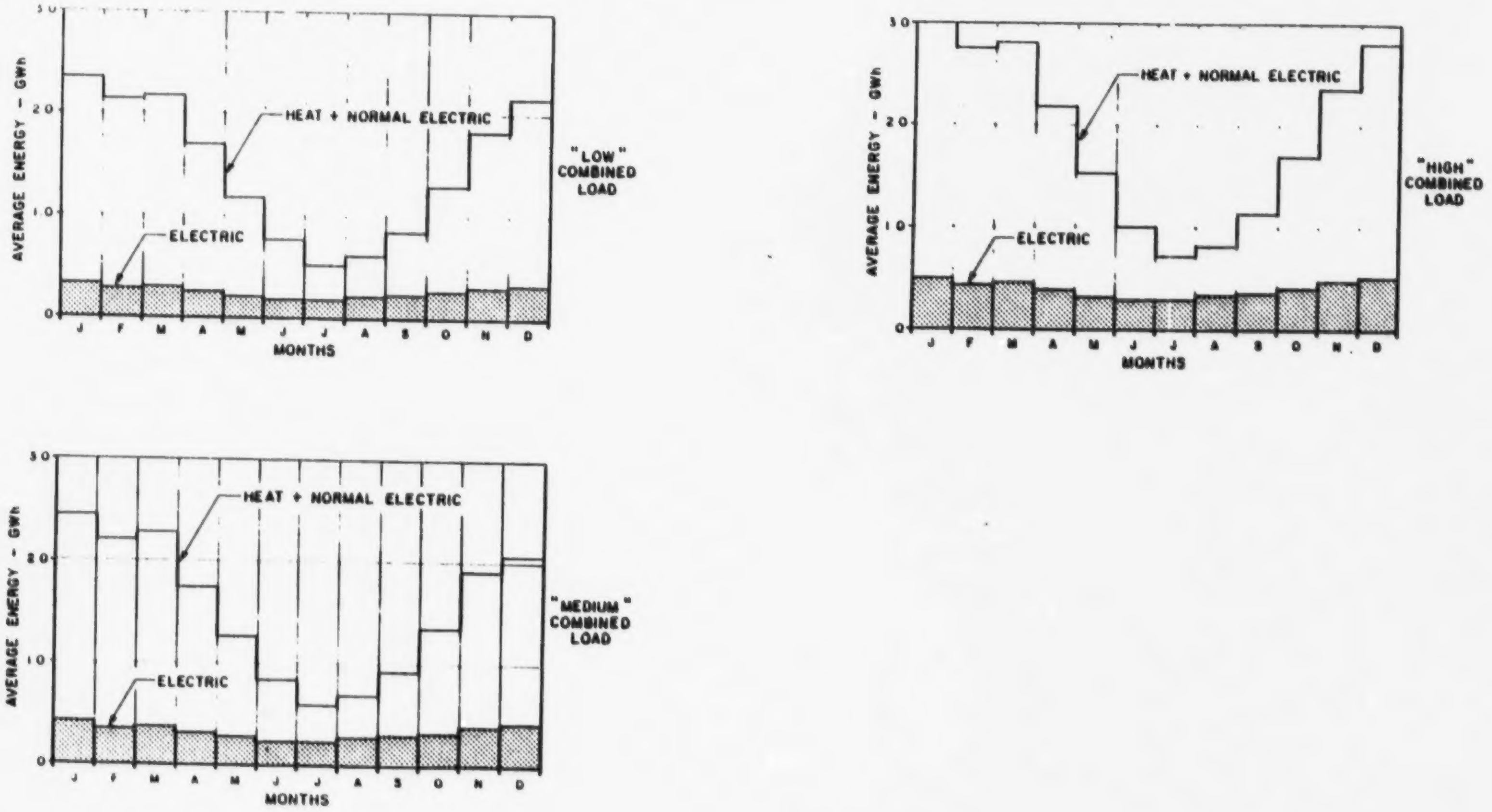
BAKER LAKE DEVELOPMENT
COST COMPARISON

FIGURE 4.1



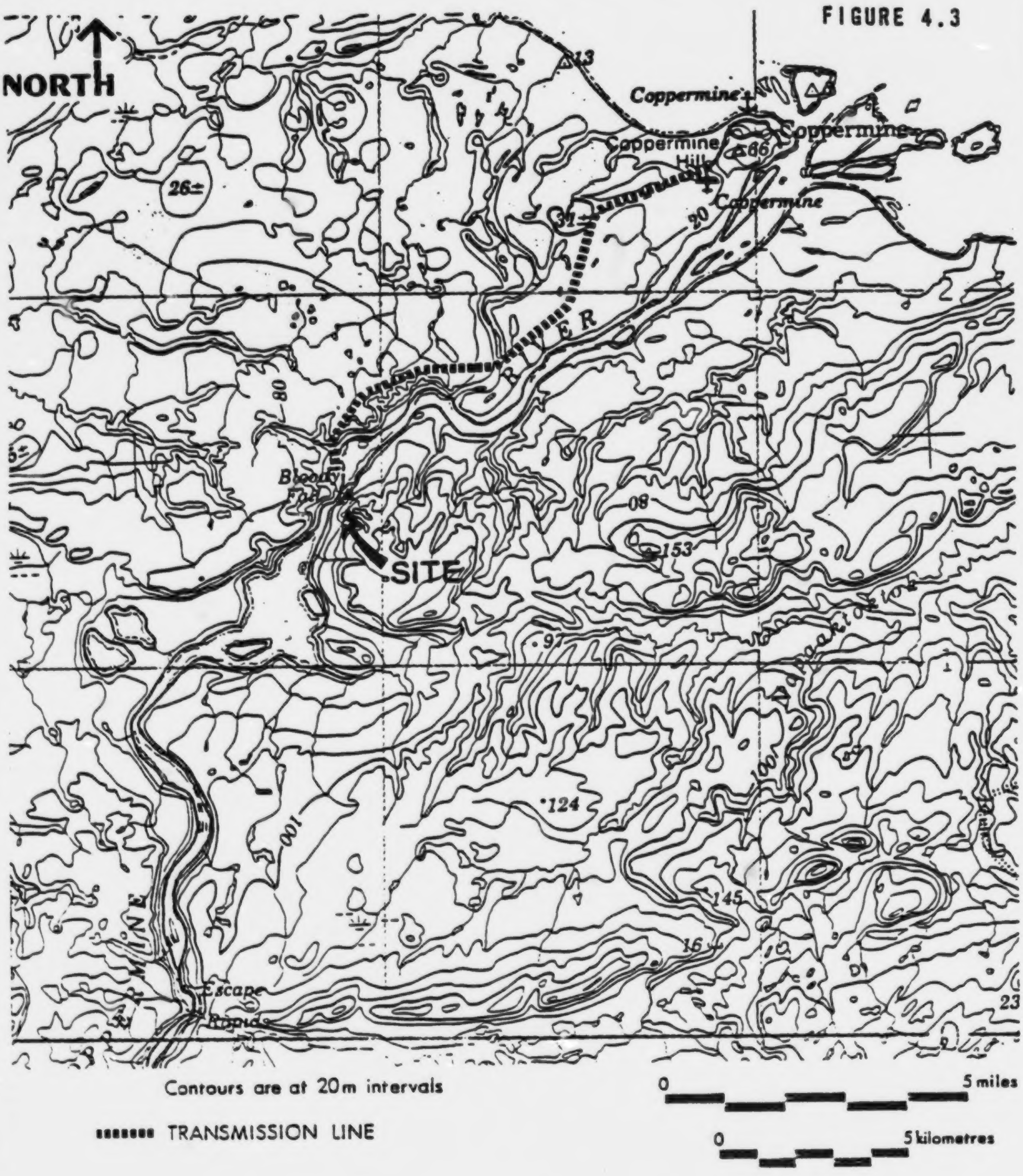
COPPERMINE DEVELOPMENT
LOAD FORECAST

FIGURE 4.2



MONTHLY LOADS, 1994
COPPERMINE

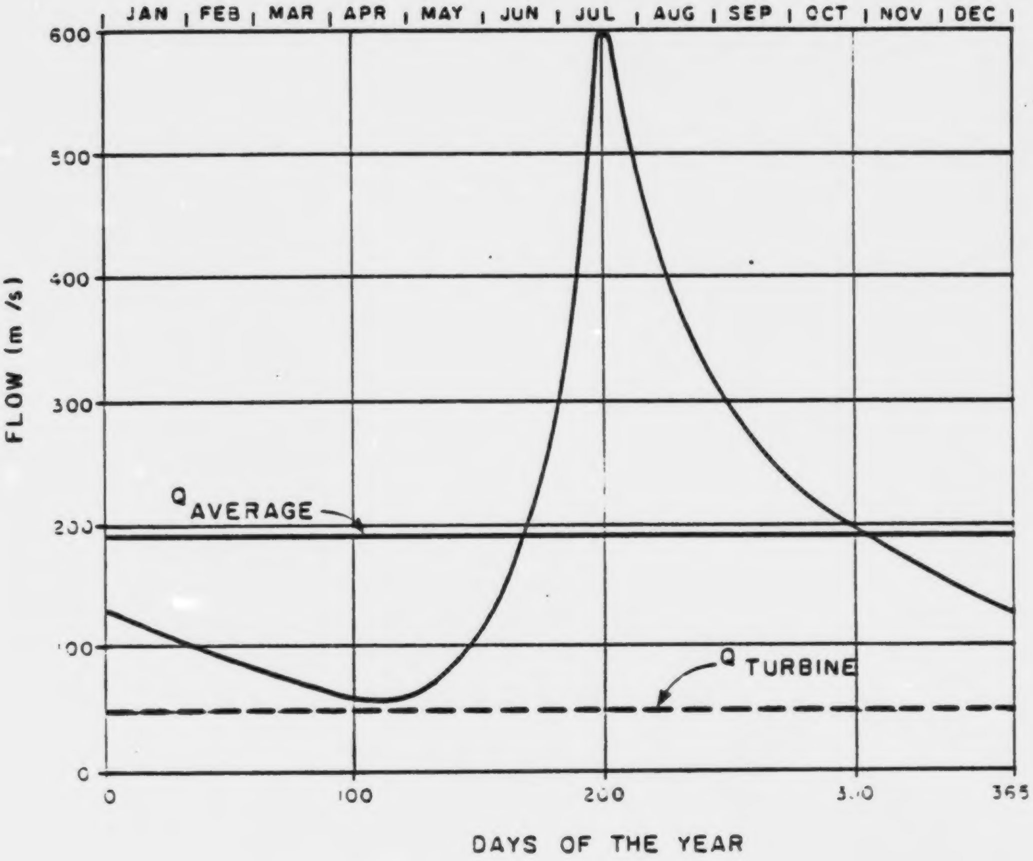
FIGURE 4.3


NORTH
13
Coppermine
Coppermine
Coppermine Hill
66
Coppermine
26±
31
20
RIVER
80
Bloody Fall
SITE
08
153
97
124
100
100
145
16
MINE
Escape Rapids
23
Contours are at 20m intervals
TRANSMISSION LINE
0
5 miles
0
5 kilometres

COPPERMINE DEVELOPMENT
SITE PLAN

hydrowest consultants inc.

FIGURE 4.4



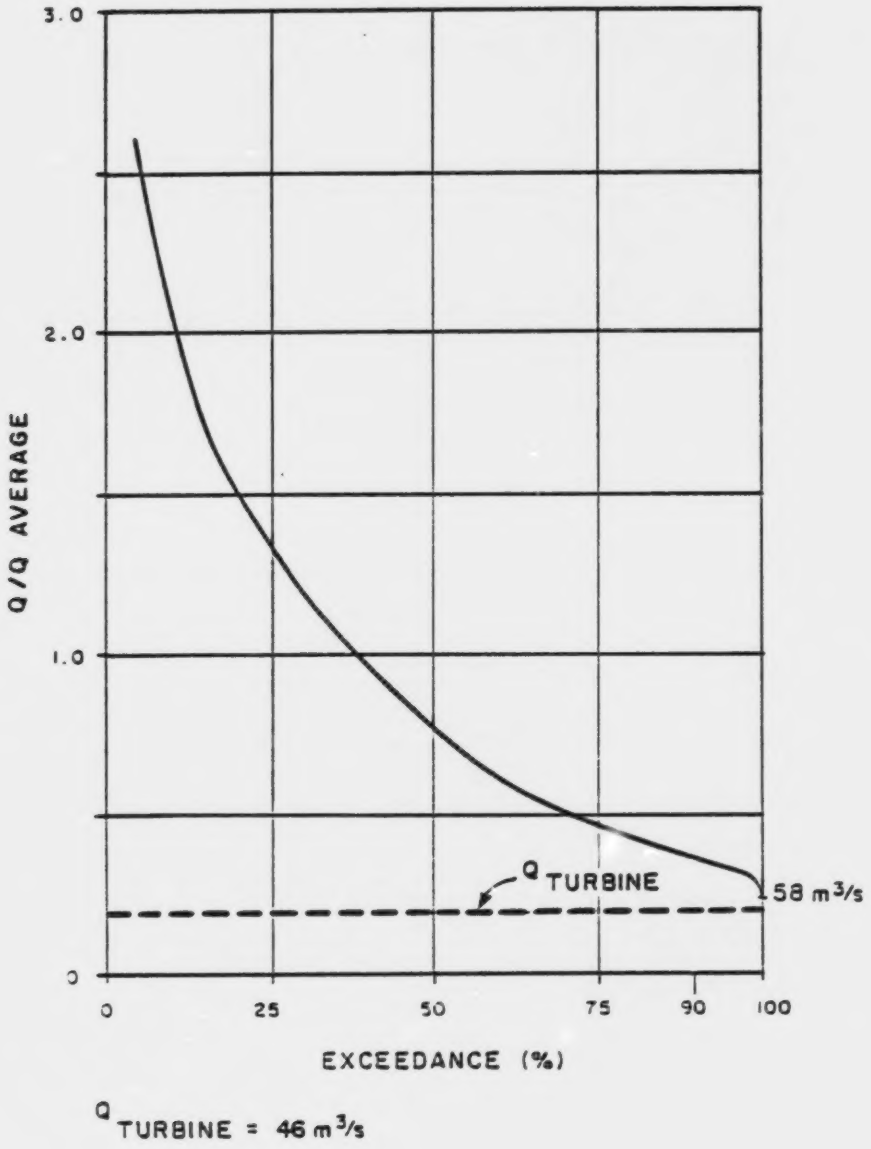
$Q_{AVERAGE}$ = 191·9 m^3/s

$Q_{MINIMUM}$ = 58·0 m^3/s

$Q_{TURBINE}$ = 46·0 m^3/s

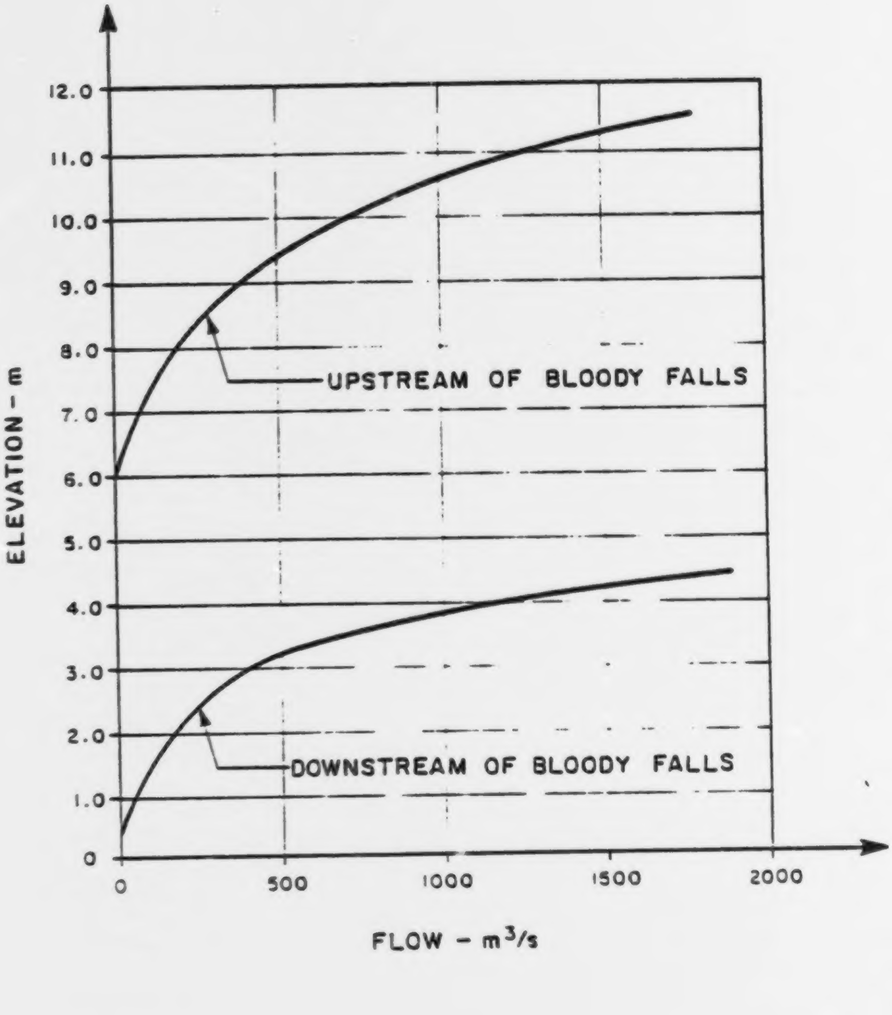
COPPERMINE DEVELOPMENT
AVERAGE DAILY FLOWS
COPPERMINE RIVER
AT BLOODY FALLS

FIGURE 4.5



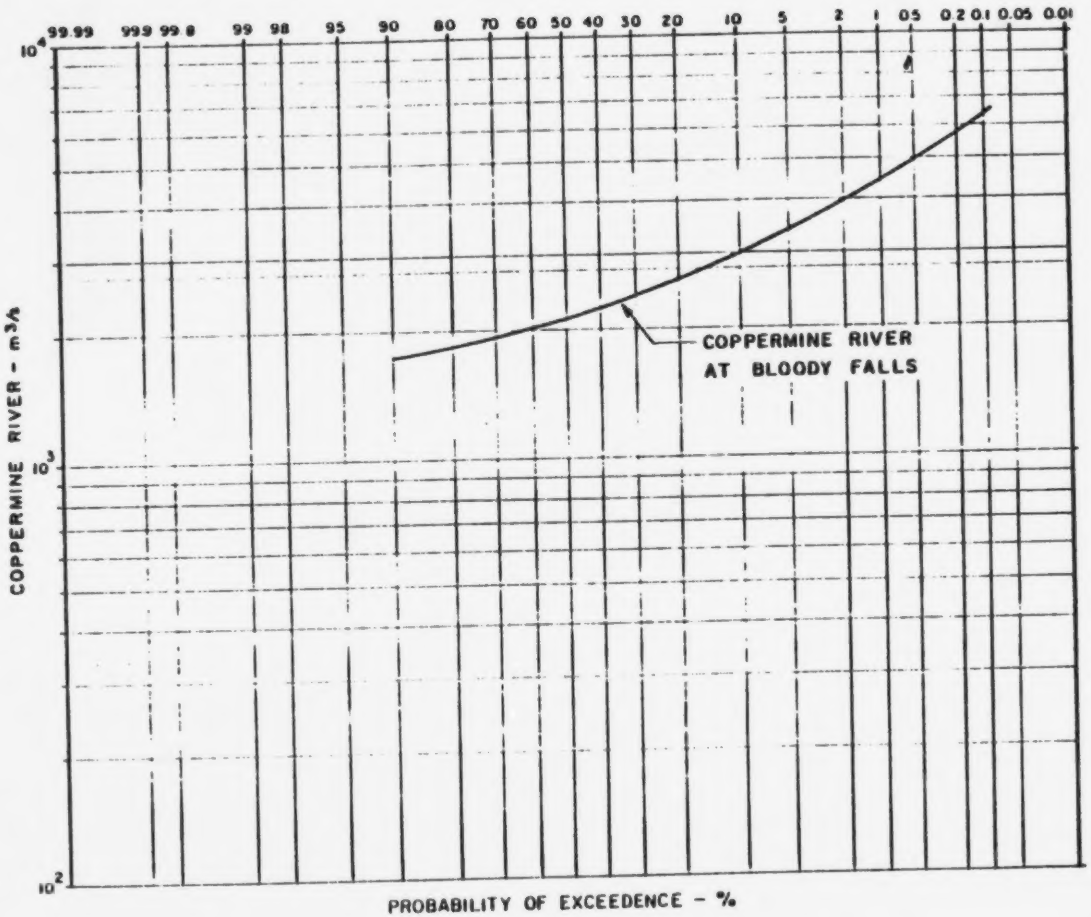
COPPERMINE DEVELOPMENT
DIMENSIONLESS DAILY FLOW
DURATION CURVE
COPPERMINE RIVER
AT BLOODY FALLS

FIGURE 4.8



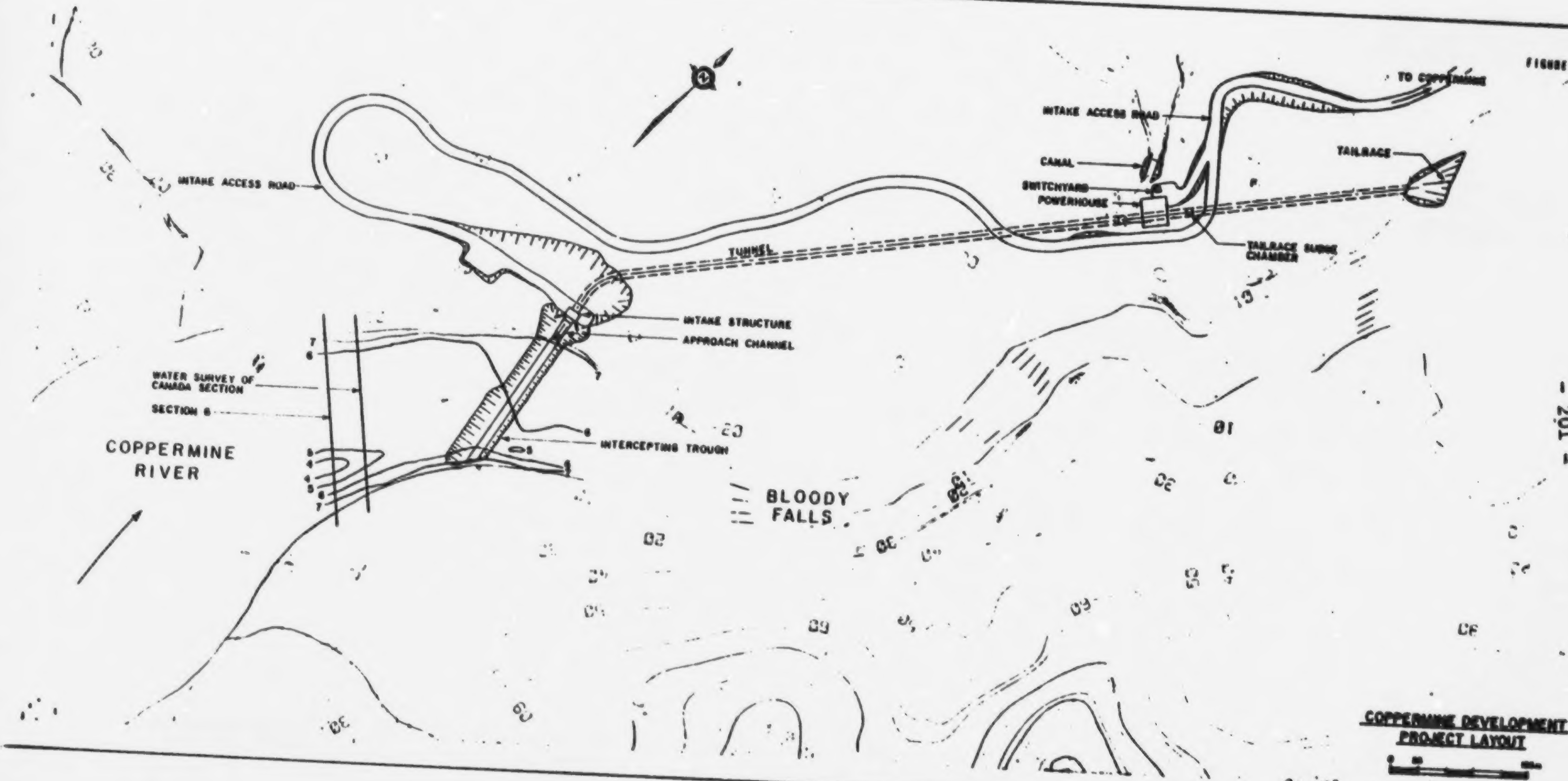
COPPERMINE DEVELOPMENT
PROVISIONAL RATING CURVES

FIGURE 4.7



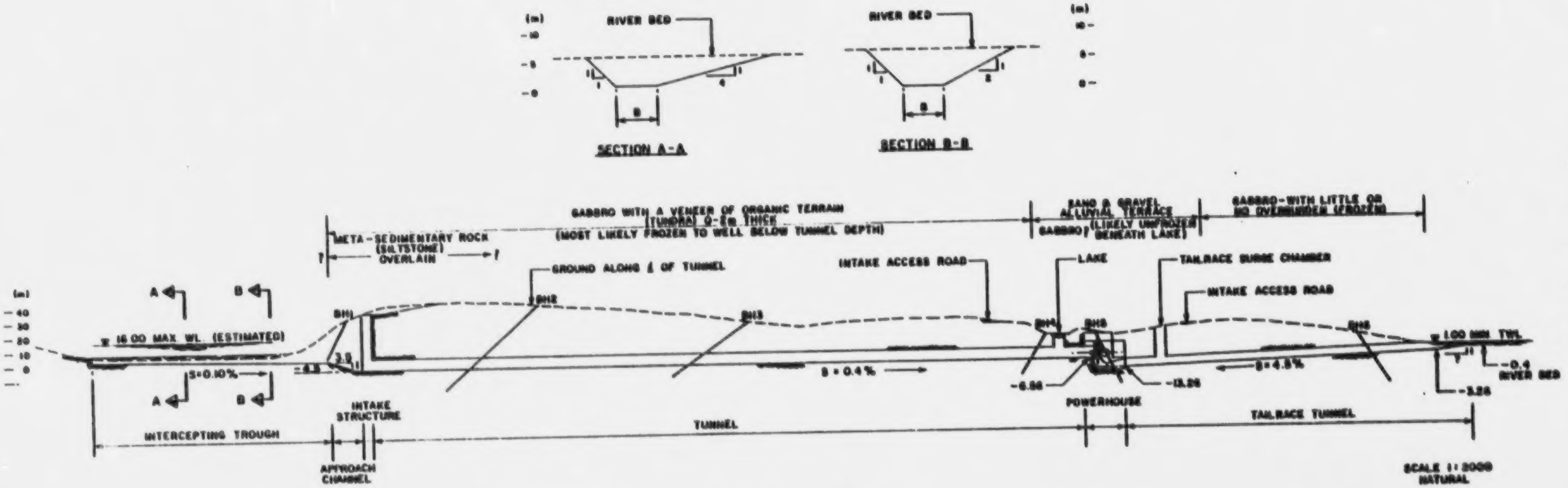
COPPERMINE DEVELOPMENT
DESIGN FLOODS

FIGURE 4.8


TO COPPERMINE
INTAKE ACCESS ROAD
CANAL
SWITCHYARD
POWERHOUSE
TAILRACE
TAILRACE SURGE CHAMBER
INTAKE ACCESS ROAD
TUNNEL
INTAKE STRUCTURE
APPROACH CHANNEL
WATER SURVEY OF CANADA SECTION
SECTION 6
INTERCEPTING TROUGH
COPPERMINE RIVER
BLOODY FALLS

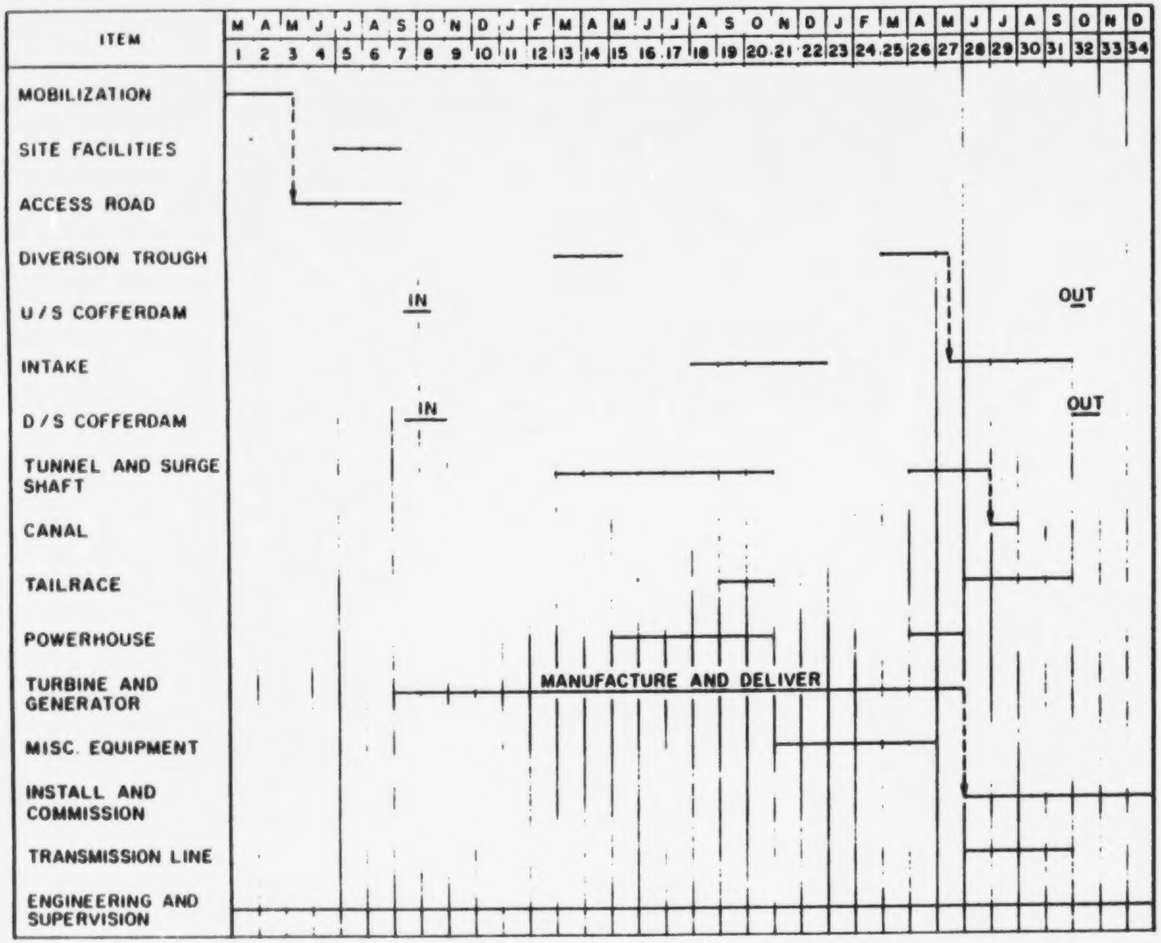
COPPERMINE DEVELOPMENT
PROJECT LAYOUT

FIGURE 4.8


(m)
-10
-5
-0
RIVER BED
1
1
4
1
B
SECTION A-A
RIVER BED
(m)
10-
5-
0-
1
1
2
1
B
SECTION B-B
META-SEDIMENTARY ROCK (SILTSTONE) OVERLAIN
GABBRO WITH A VENEER OF ORGANIC TERRAIN (TUNDRA) 0-2m THICK (MOST LIKELY FROZEN TO WELL BELOW TUNNEL DEPTH)
SAND & GRAVEL ALLUVIAL TERRACE
GABBRO? (LIKELY UNFROZEN BENEATH LAKE)
GABBRO-WITH LITTLE OR NO OVERBURDEN (FROZEN)
GROUND ALONG ℄ OF TUNNEL
INTAKE ACCESS ROAD
LAKE
TAILRACE SURGE CHAMBER
INTAKE ACCESS ROAD
(m)
- 40
- 30
- 20
- 10
- 0
A
B
A
B
16.00 MAX WL (ESTIMATED)
S=0.10%
BH1
BH2
BH3
BH4
BH5
BH6
3.5
-4.5
S = 0.4%
S=4.5%
-6.56
-13.26
1.00 MIN TWL
-0.4 RIVER BED
-3.26
INTERCEPTING TROUGH
INTAKE STRUCTURE
APPROACH CHANNEL
TUNNEL
POWERHOUSE
TAILRACE TUNNEL
(m)
- 40
- 30
- 20
- 10
- 0
SCALE 1:2000 NATURAL

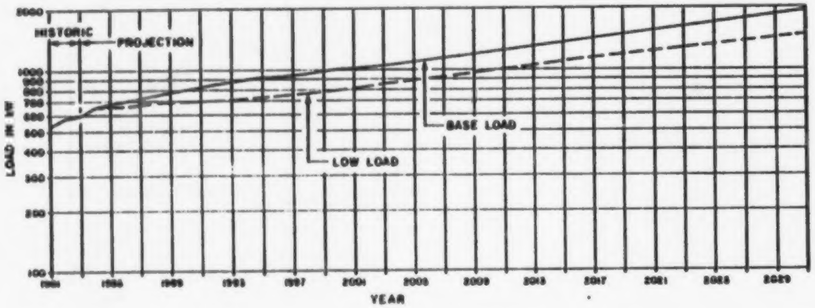
COPPERMINE DEVELOPMENT
DEVELOPED PROFILE ALONG INTAKE, TUNNEL AND POWERHOUSE

FIGURE 4.10

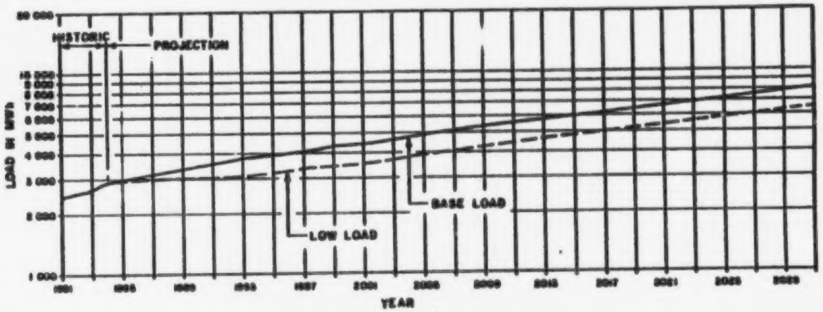


COPPERMINE DEVELOPMENT
CONSTRUCTION SCHEDULE

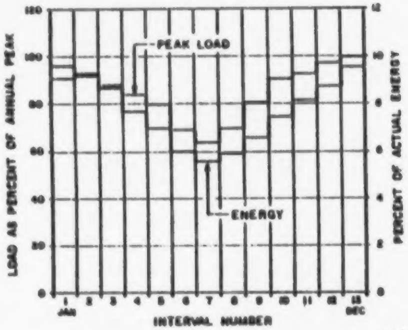
FIGURE 4.11



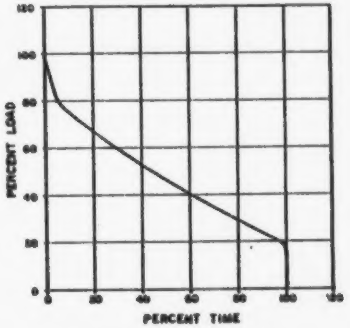
PEAK CURVE



ENERGY CONSUMPTION CURVE



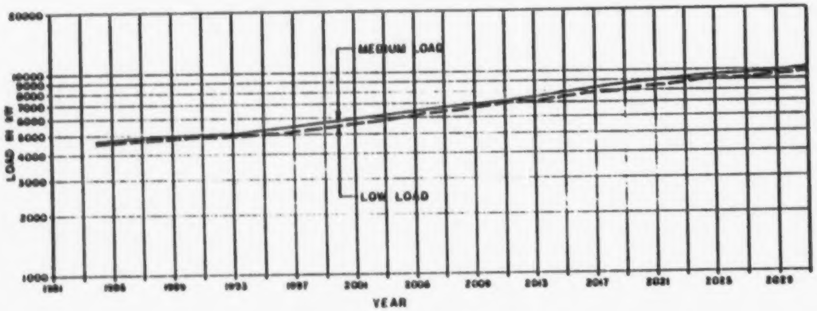
PEAK LOAD AND ENERGY VERSUS INTERVAL



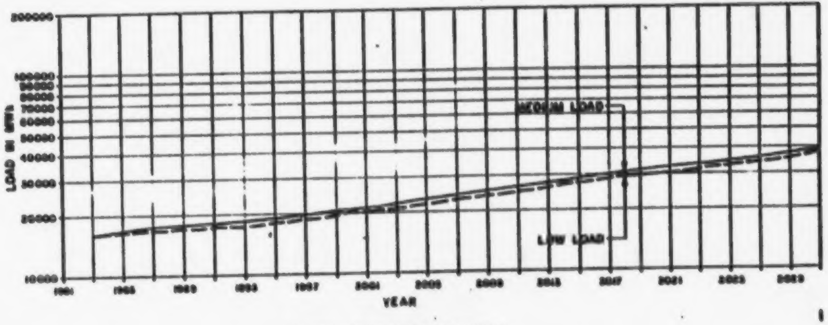
ANNUAL LOAD DURATION CURVE

COPPERMINE DEVELOPMENT
ELECTRICAL SYSTEM
LOAD CHARACTERISTICS

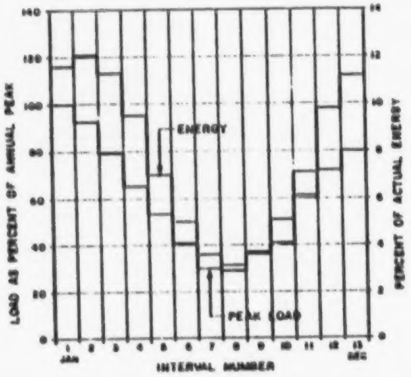
FIGURE 4.12



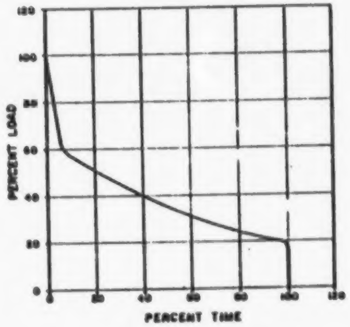
PEAK CURVE



ENERGY CONSUMPTION CURVE



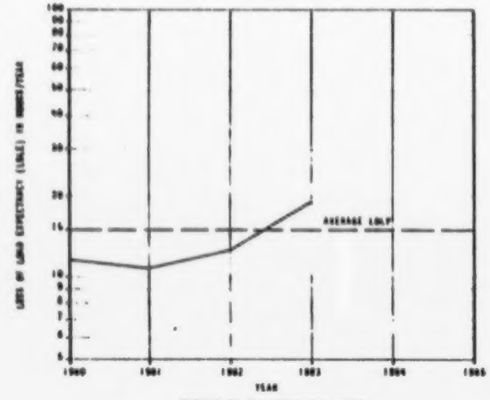
PEAK LOAD AND ENERGY VERSUS INTERVAL



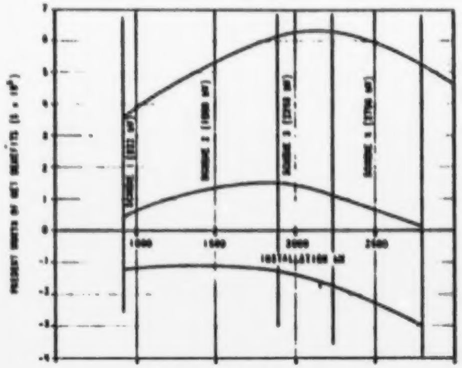
ANNUAL LOAD DURATION CURVE

COPPERMINE DEVELOPMENT
COMBINED (ELEC. + HEAT)
LOAD CHARACTERISTICS

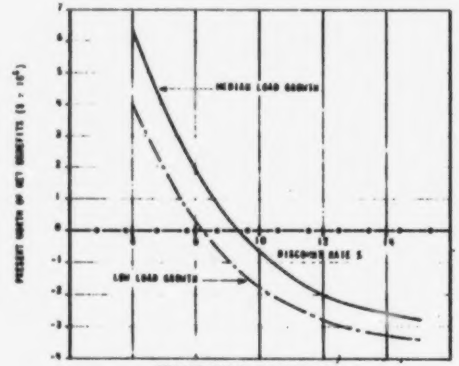
FIGURE 4.13



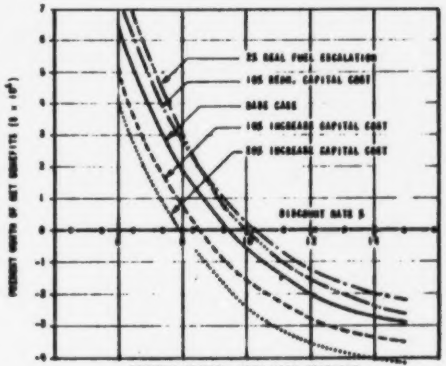
CHOICE OF RELIABILITY INDEX



SELECTION OF THE BEST SCHEMES
ALL HYDRO COMMISSIONED JAN. 1980



OPTIMUM SCENE, NO ESCALATION
COMMISSIONING YEAR = JAN. 1982



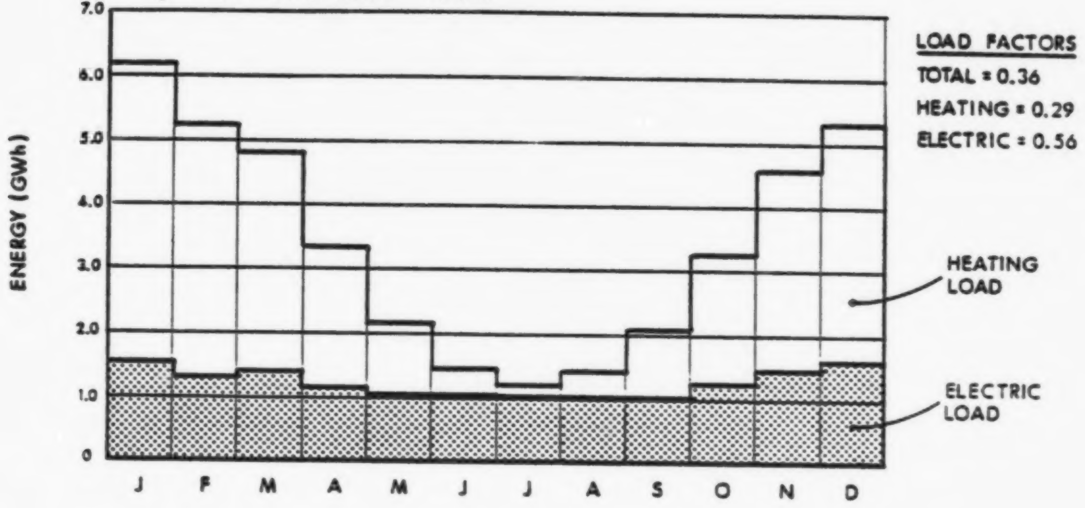
OPTIMUM SCHEME, BASE LOAD FORECAST
COMMISSIONING YEAR = JAN. 1982

NOTES

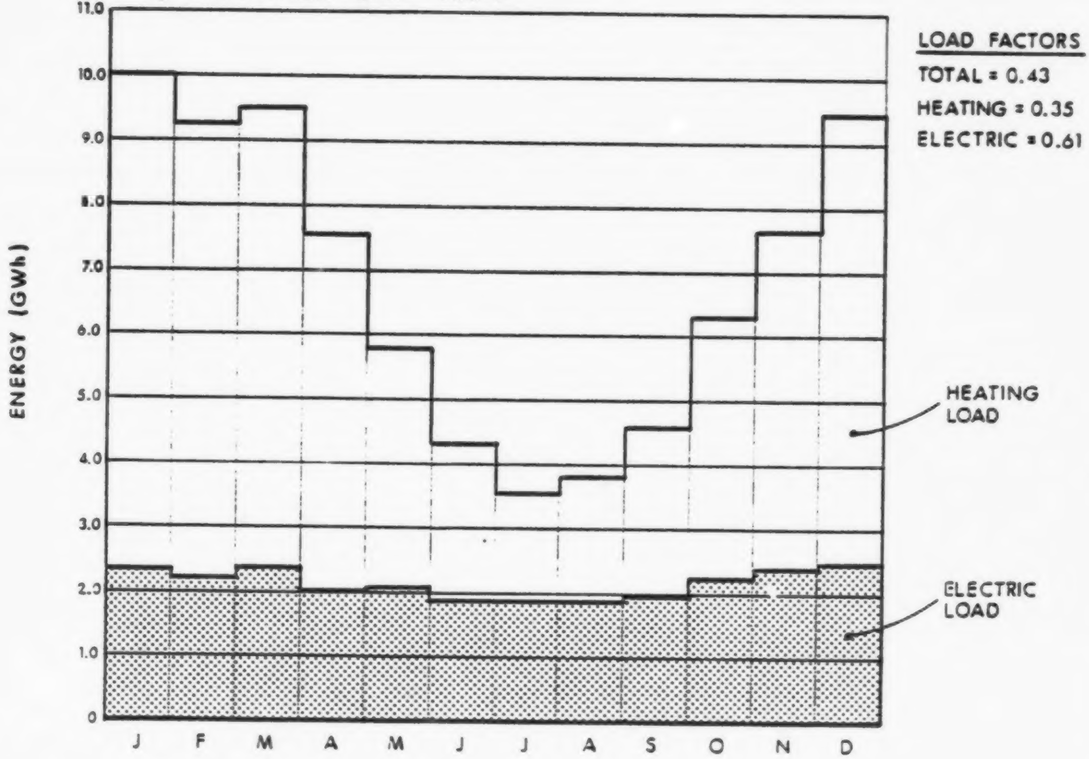
NET BENEFIT = SYSTEM CAPITAL AND
OPERATION COSTS WITHOUT HYDRO
LESS SYSTEM COSTS WITH HYDRO,
PLUS HEATING CREDIT

COPPERMINE DEVELOPMENT
PROJECT EVALUATION
INTERNAL RATES OF RETURN

FIGURE 5.1



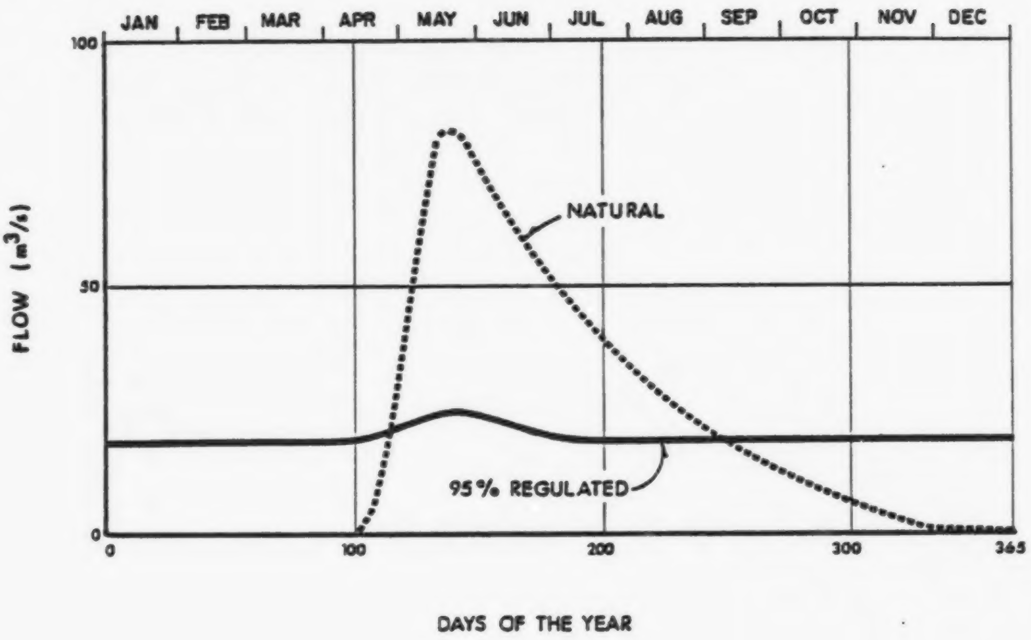
a) FORT SIMPSON - 1994



b) FROBISHER BAY - 1994

MONTHLY LOADS

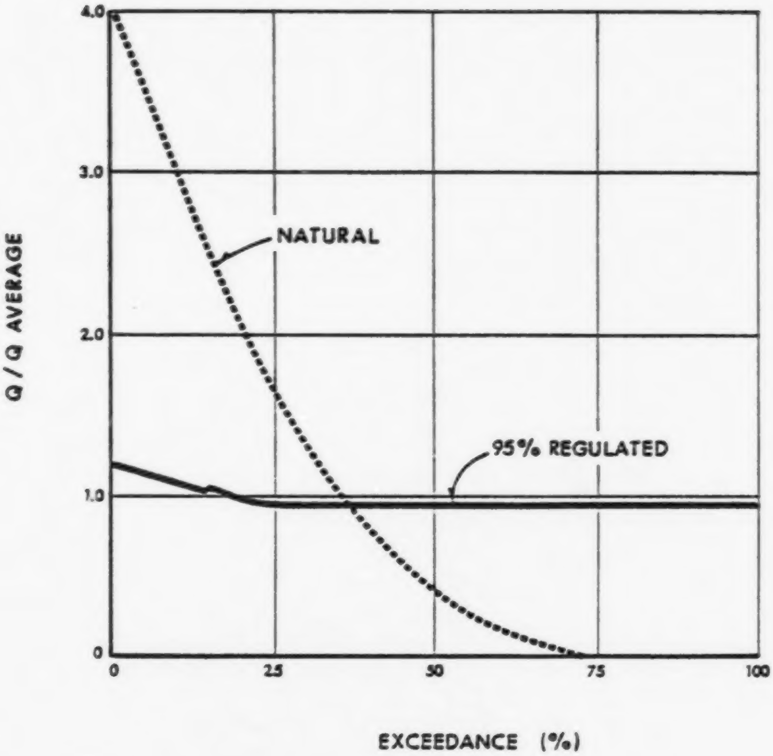
FIGURE 5.2



AVERAGE = 20.57 m^3/s

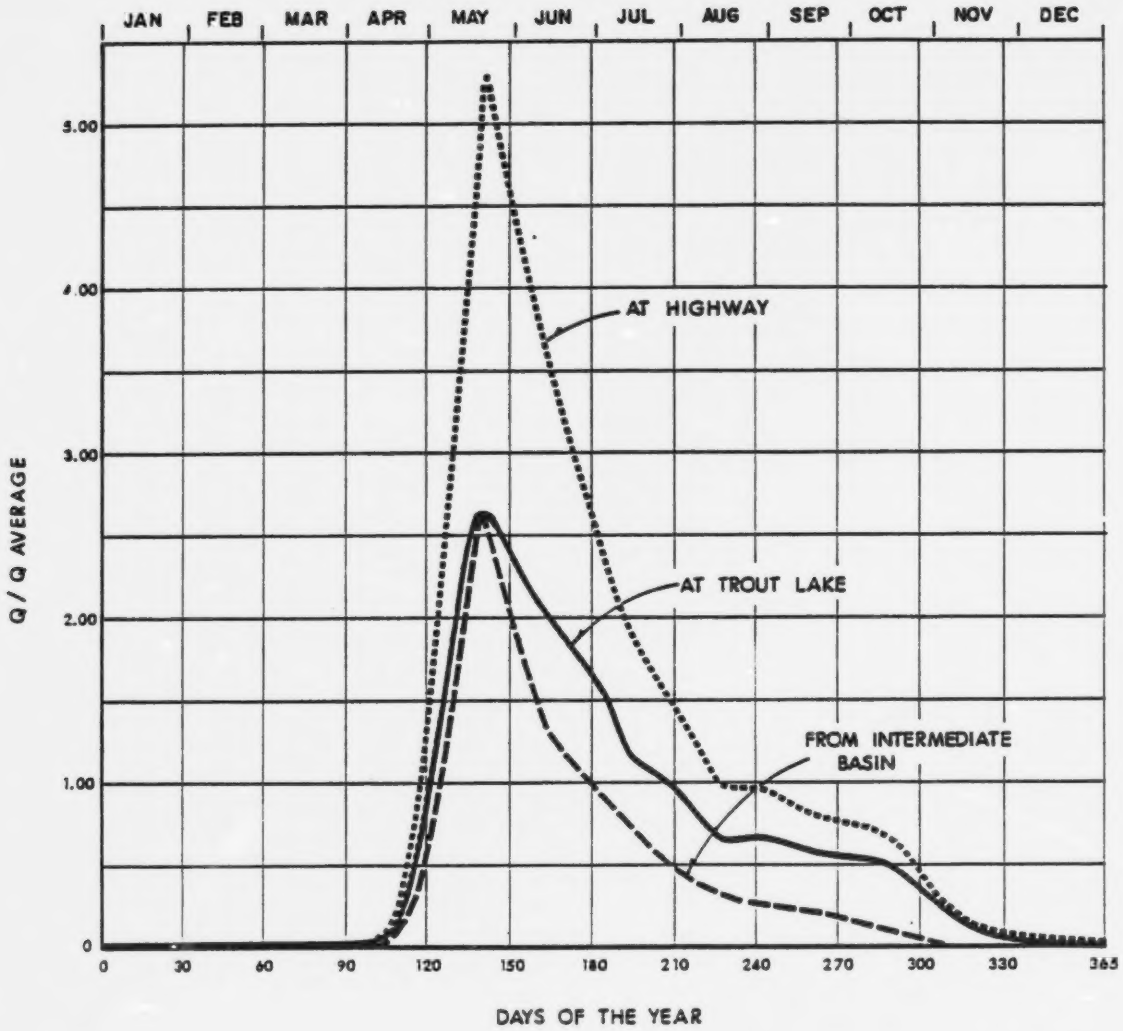
AVERAGE DAILY FLOWS
TROUT RIVER AT TROUT LAKE

FIGURE 5.3



DIMENSIONLESS
DAILY FLOW DURATION CURVE
TROUT RIVER AT TROUT LAKE

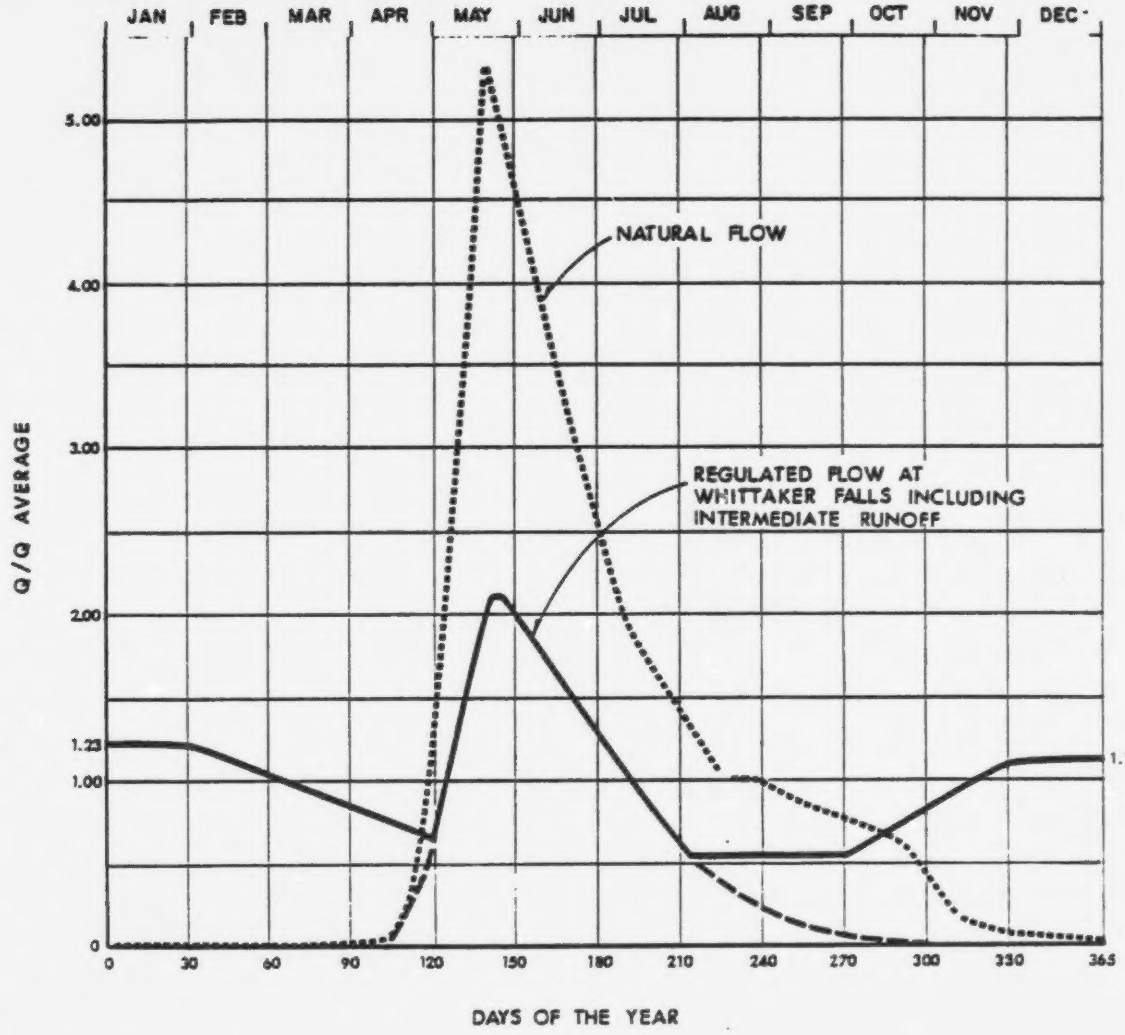
FIGURE 5.4



Qav AT HIGHWAY = 31.91 m^3/s

DAILY FLOWS
IN TROUT RIVER

FIGURE 5.5

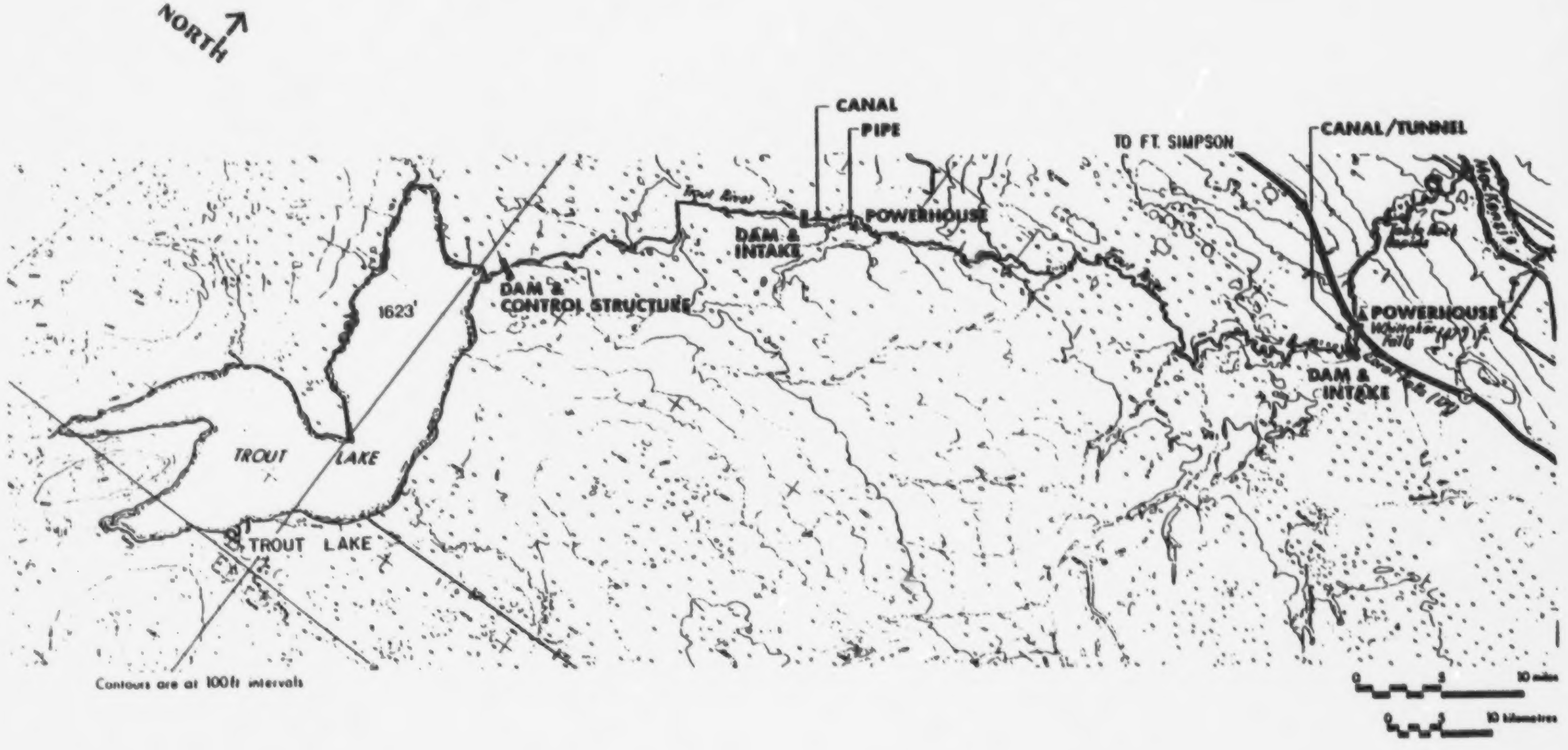


Qav = 31.91 m³/s AT HIGHWAY

AVERAGE OUTFLOW FROM
TROUT LAKE (95% REGULATION)
Q = 19.54 m³/s

AVERAGE
OPERATIONAL FLOWS
TROUT RIVER AT HIGHWAY

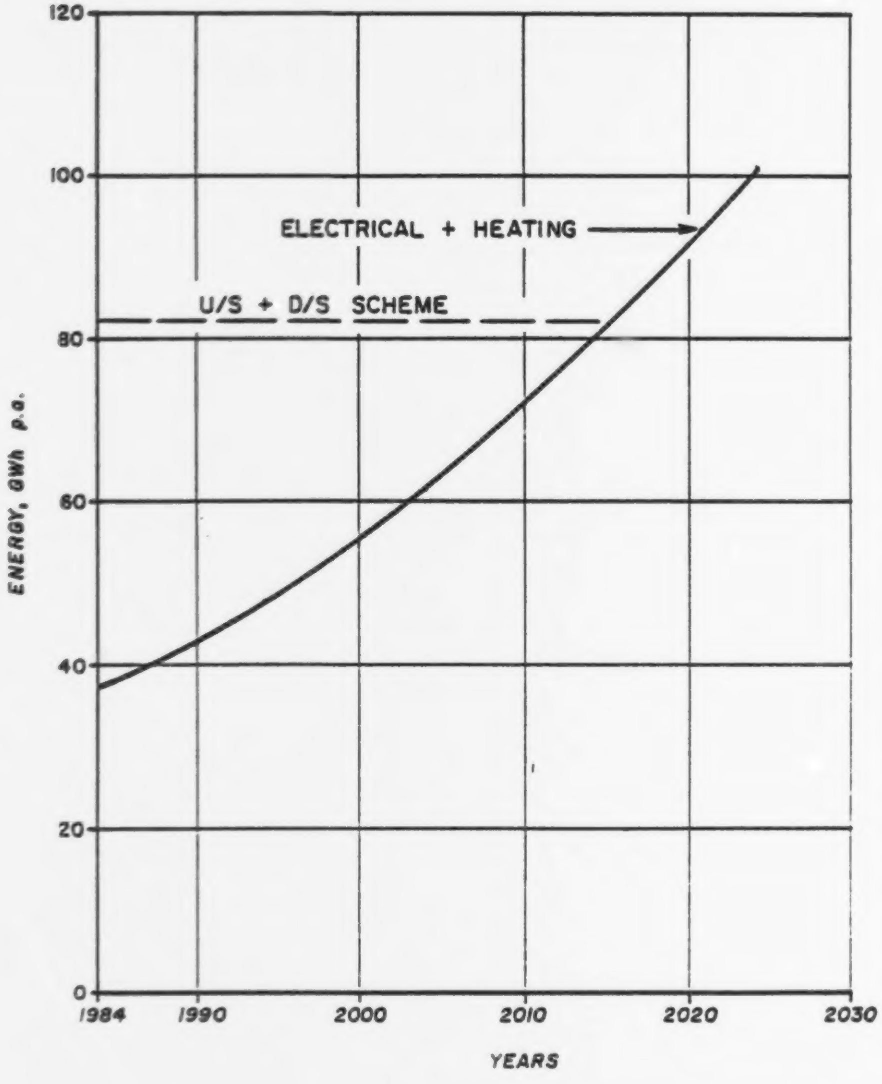
FIGURE 5.8


NORTH
CANAL
PIPE
POWERHOUSE
DAM & INTAKE
Trout River
DAM & CONTROL STRUCTURE
1623'
TROUT LAKE
TROUT LAKE
TO FT. SIMPSON
CANAL/TUNNEL
Mackenzie
POWERHOUSE
Whittaker Falls
DAM & INTAKE
Contours are at 100ft intervals
0 5 10 miles
0 5 10 kilometres

FORT SIMPSON DEVELOPMENT

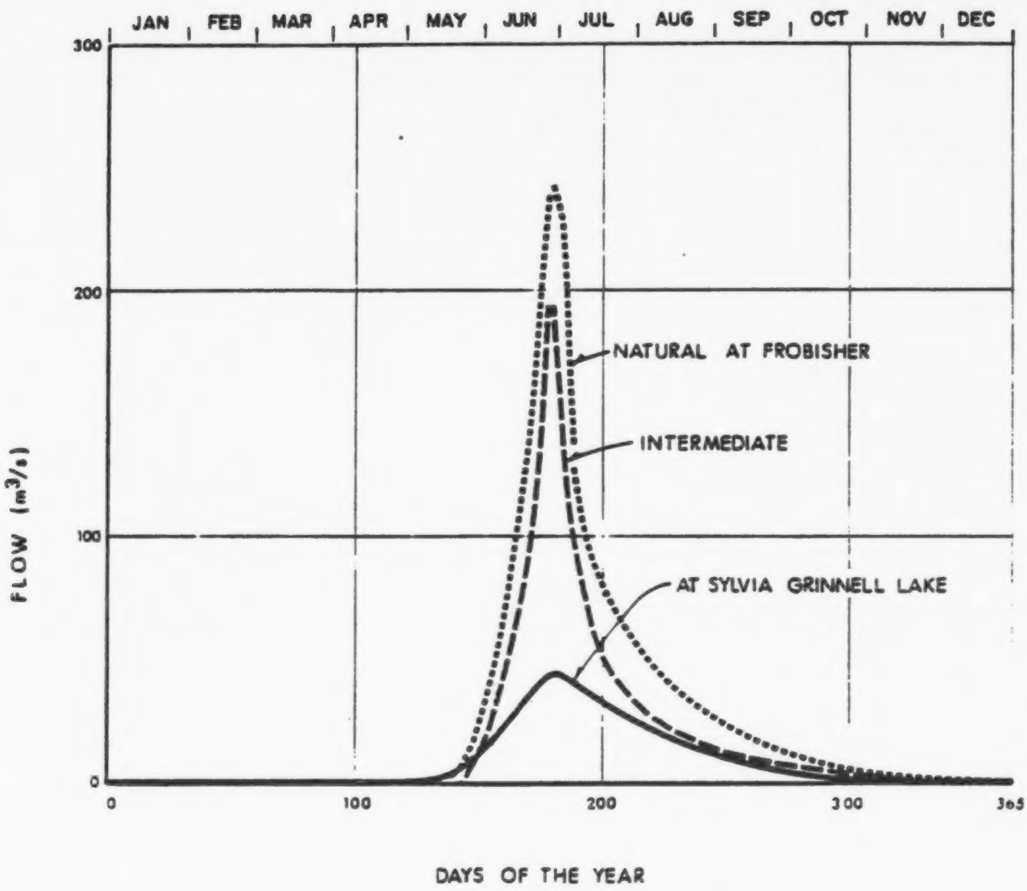
hydrowest consultants inc.

FIGURE 5.7



RELATION BETWEEN LOAD GROWTH AND PROPOSED SCHEME
FORT SIMPSON

FIGURE 6.1

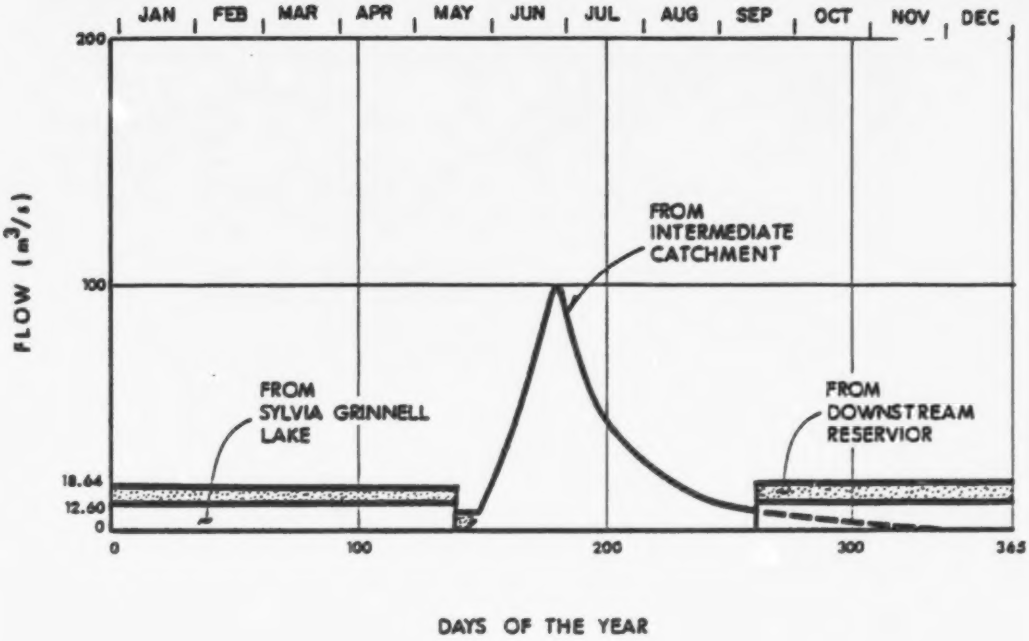


AVERAGE AT LAKE OUTLET 9.34 m³/s

AVERAGE AT FROBISHER 24.2 m³/s

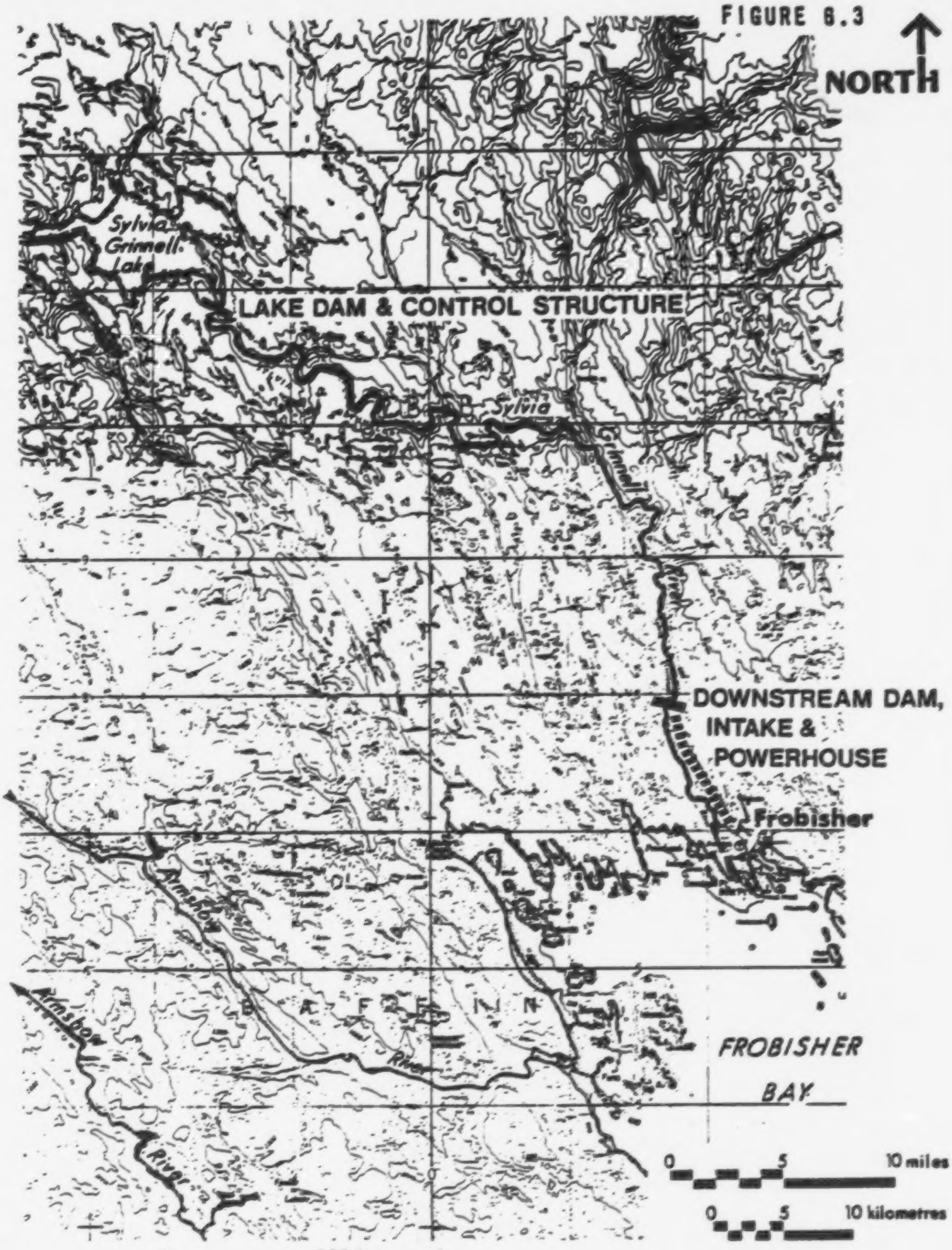
AVERAGE DAILY FLOWS
SYLVIA GRINNELL RIVER

FIGURE 6.2



AVERAGE
OPERATIONAL FLOWS
SYLVIA GRINNELL RIVER

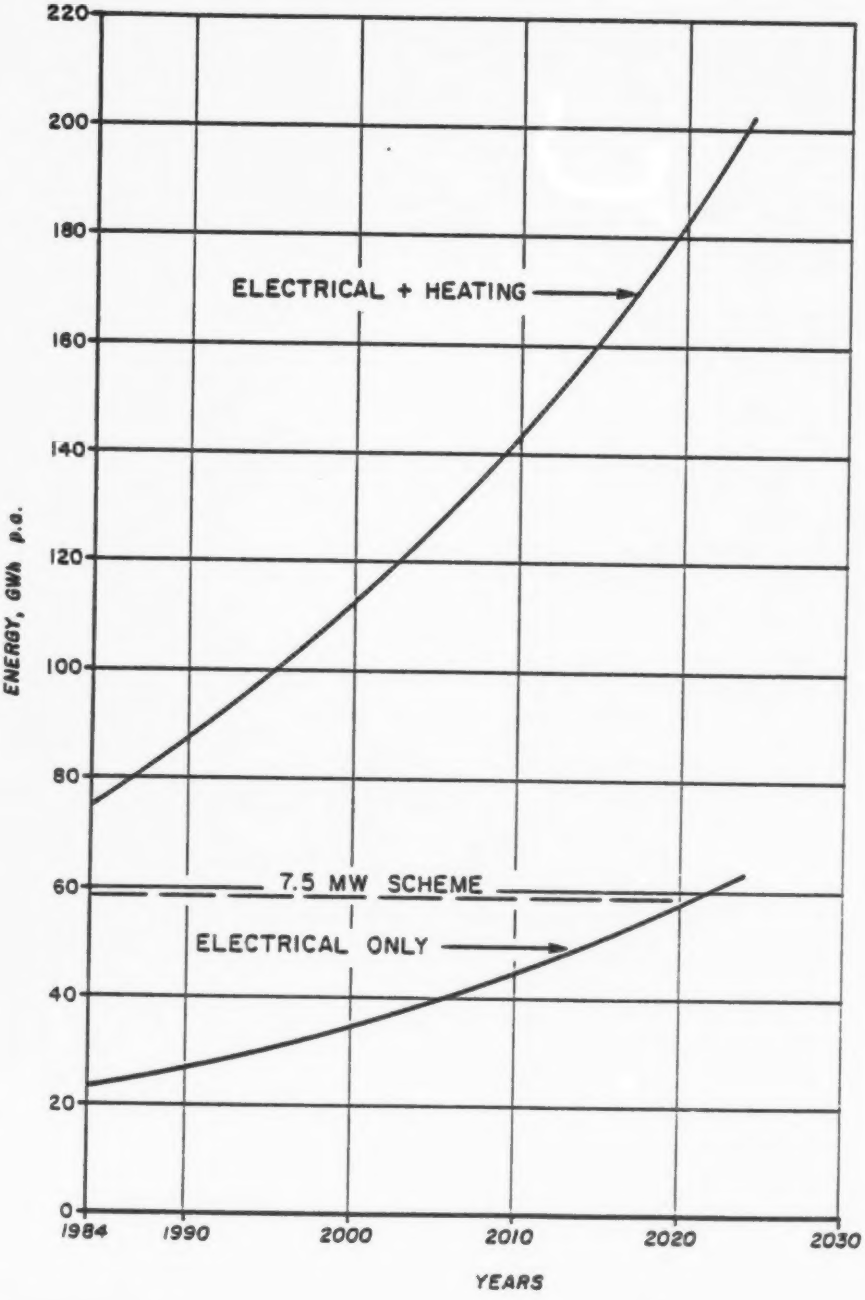
FIGURE 6.3


NORTH
Sylvia Grinnell Lake
LAKE DAM & CONTROL STRUCTURE
Sylvia Grinnell
DOWNSTREAM DAM, INTAKE & POWERHOUSE
Frobisher
Armshow
Armshow River
River
B A F F I N
FROBISHER BAY
0 5 10 miles
0 5 10 kilometres

Contours are at 200 ft intervals

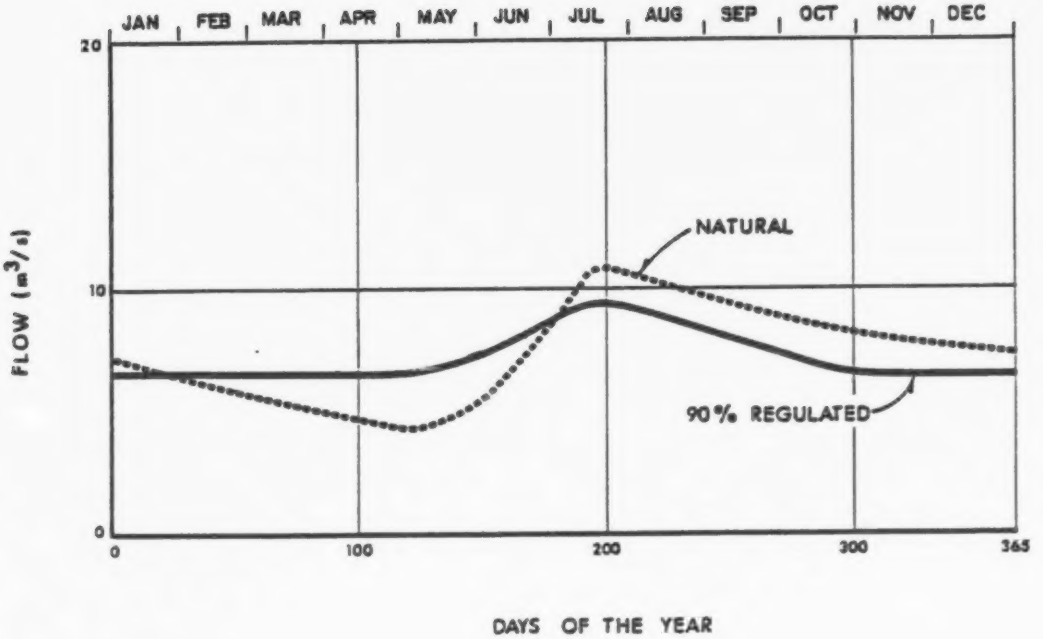
▪▪▪▪▪▪ TRANSMISSION LINE

FIGURE 6.4



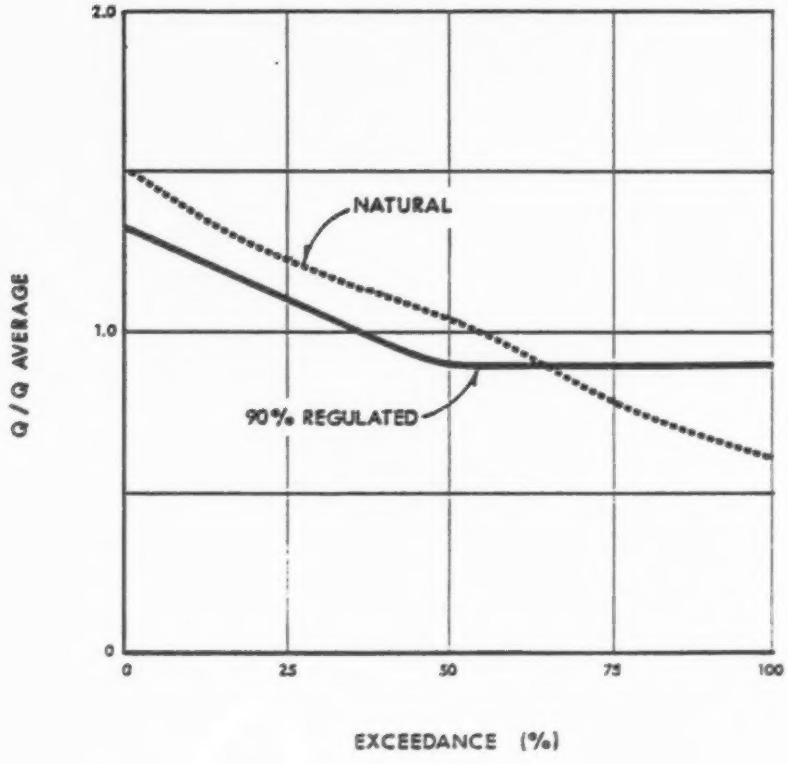
RELATION BETWEEN LOAD GROWTH AND PROPOSED SCHEME
FROBISHER BAY

FIGURE 7.1



AVERAGE DAILY FLOWS
CAMSELL RIVER AT
THE OUTLET OF FABER LAKE

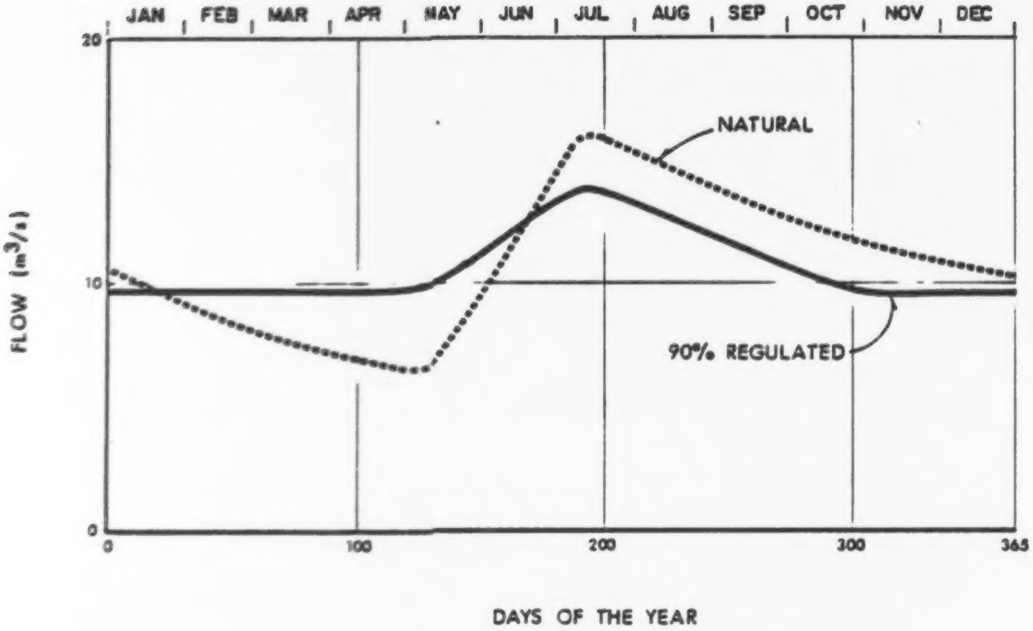
FIGURE 7.2



$Q_{av.} = 7.28\ m^3/s$

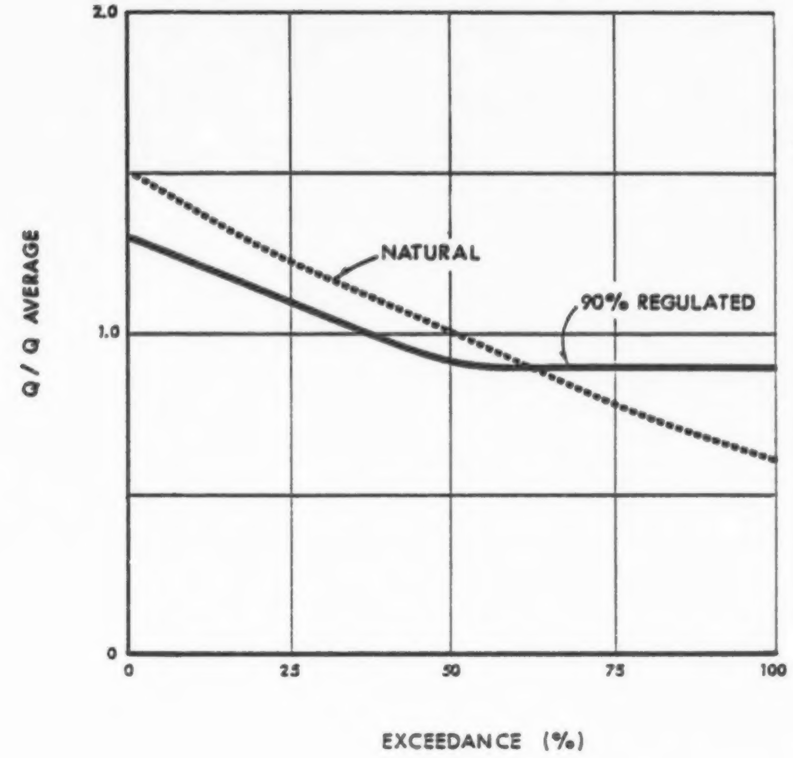
DIMENSIONLESS
DAILY FLOW DURATION CURVE
CAMSELL RIVER AT
THE OUTLET OF FABER LAKE

FIGURE 7.3



AVERAGE DAILY FLOWS
CAMSELL RIVER AT RAE LAKES

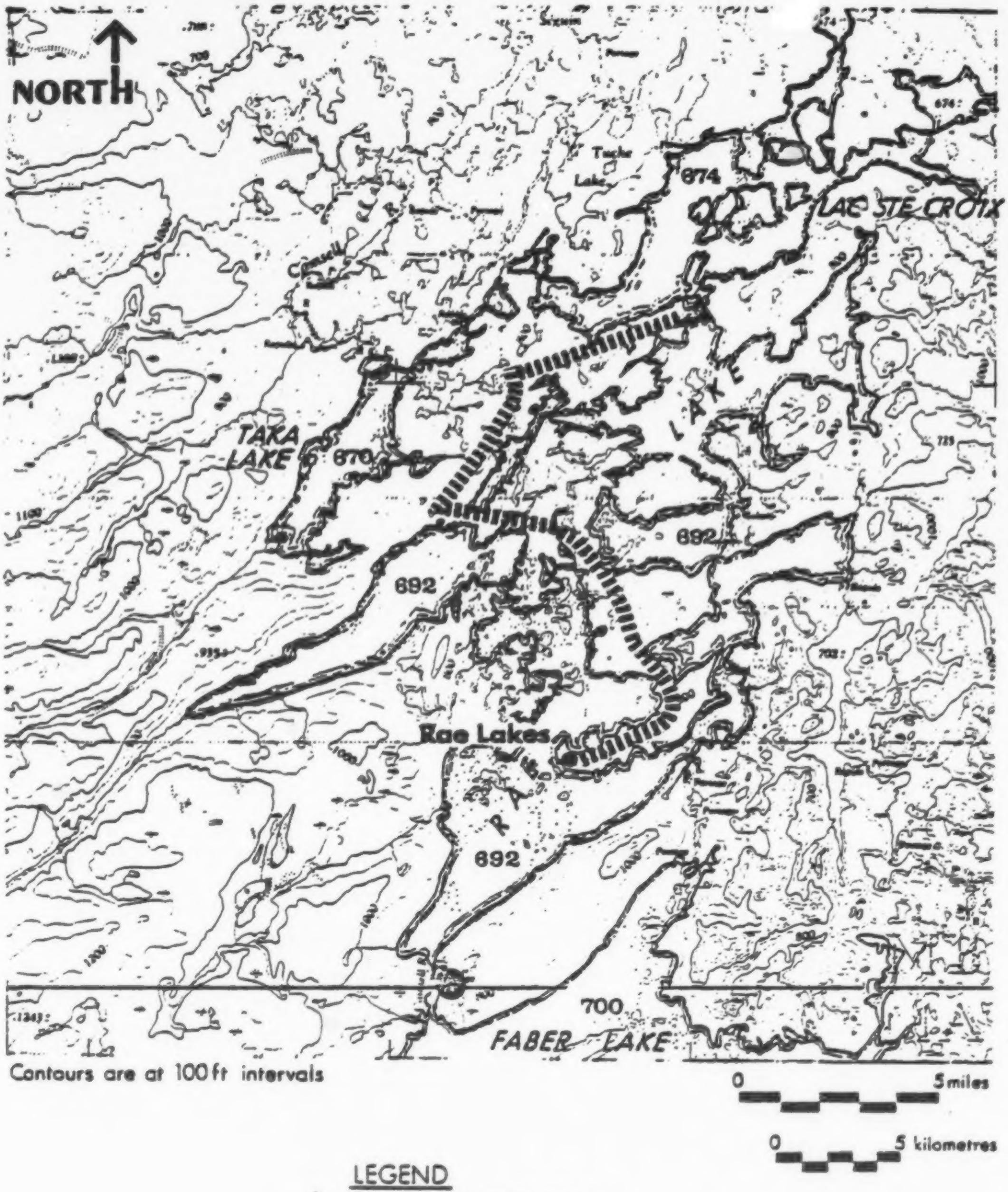
FIGURE 7.4



$Q_{av} = 10.29\ m^3/s$

DIMENSIONLESS
DAILY FLOW DURATION CURVE
CAMSELL RIVER AT RAE LAKES

FIGURE 7.5


NORTH
TAKA LAKE
670
674
LAC STE CROIX
LAKE
692
692
692
Rae Lakes
RAE
700
FABER LAKE
Contours are at 100 ft intervals
0
5 miles
0
5 kilometres

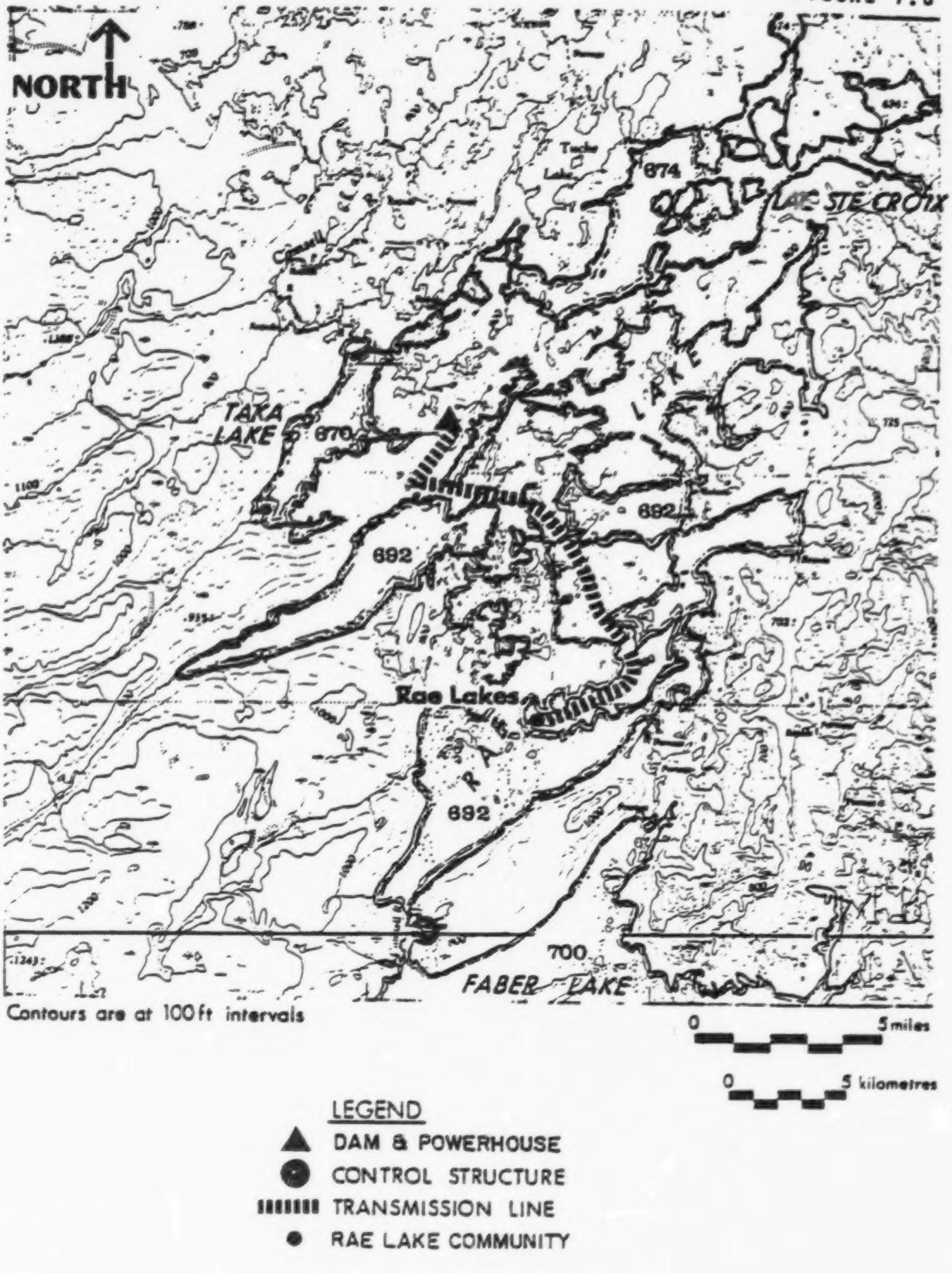
LEGEND

- ▲ DAM & POWERHOUSE
- ● CONTROL STRUCTURE
- ▮▮▮▮▮▮▮ TRANSMISSION LINE
- • RAE LAKE COMMUNITY

hydrowest consultants inc.

RAE LAKES
RAE LAKE / LAC STE CROIX DEVELOPMENT

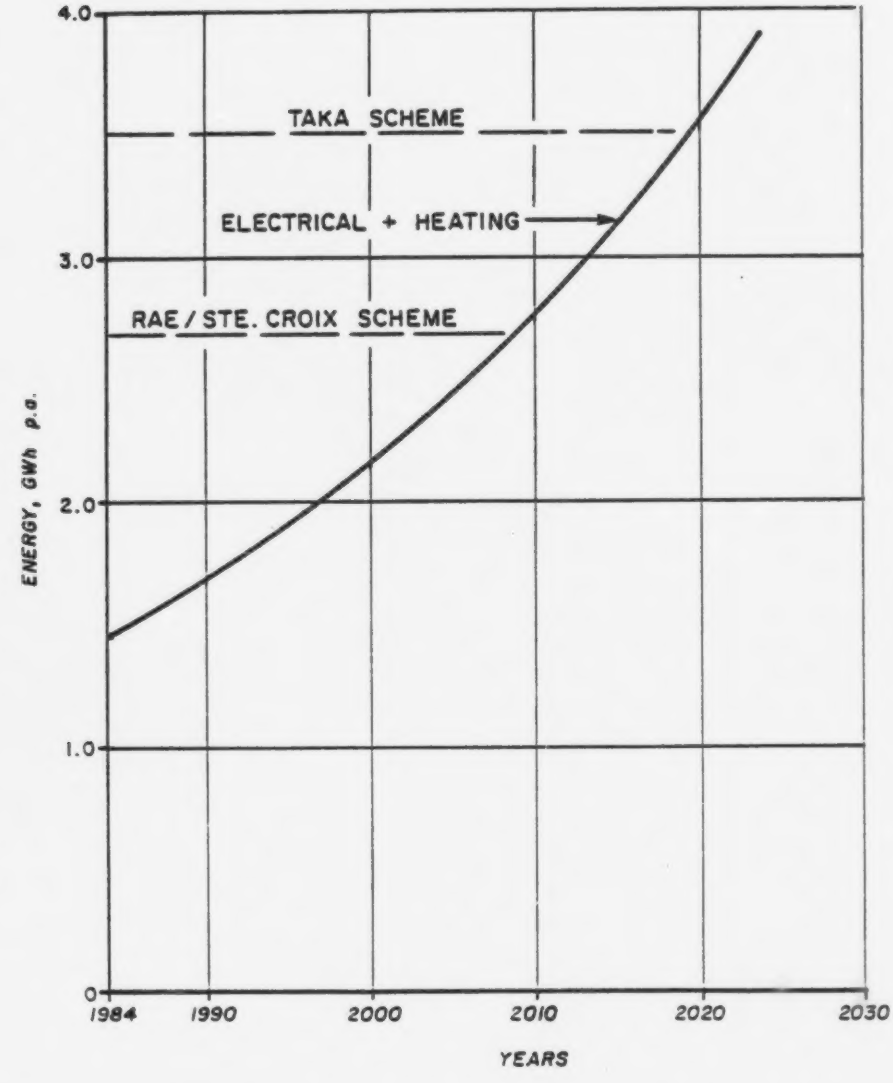
FIGURE 7.6


NORTH
TAKA LAKE
670
674
LAC STE CROIX
LAKE
692
692
Rae Lakes
RAE
692
700
FABER LAKE
Contours are at 100ft intervals
0
5 miles
0
5 kilometres
LEGEND
▲ DAM & POWERHOUSE
● CONTROL STRUCTURE
TRANSMISSION LINE
● RAE LAKE COMMUNITY

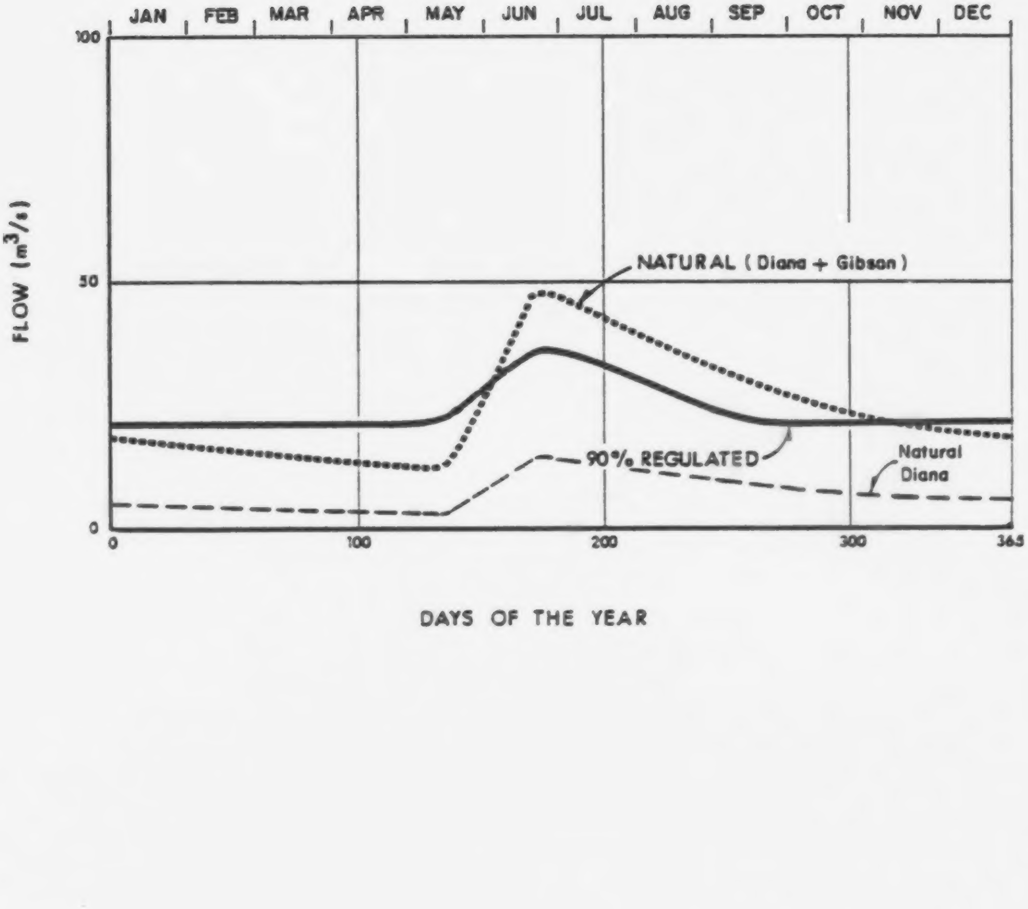
hydrowest consultants inc.

RAE LAKES
RAE LAKE / TAKA LAKE DEVELOPMENT

FIGURE 7.7

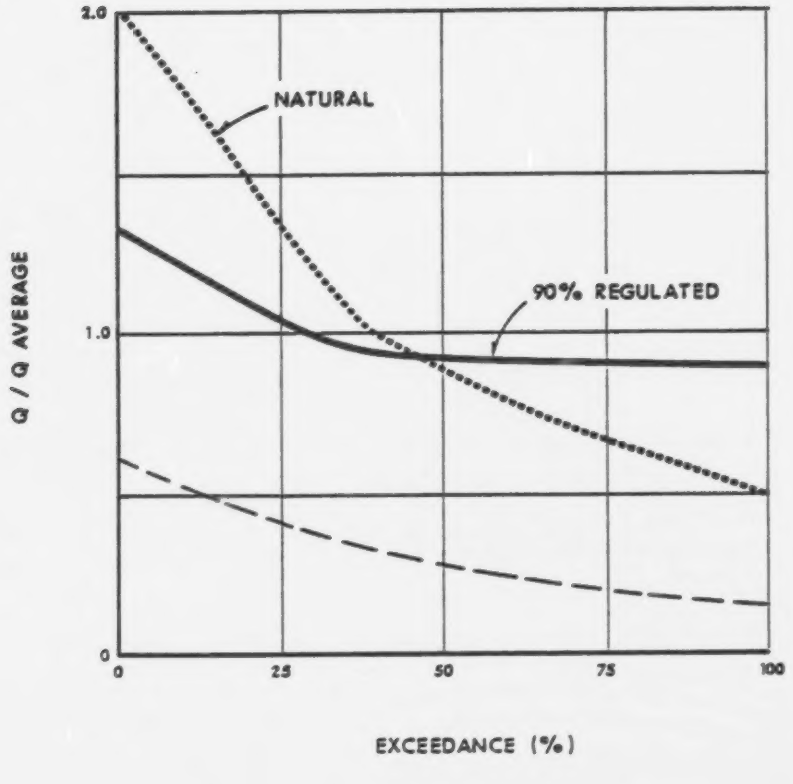


RELATION BETWEEN LOAD GROWTH AND PROPOSED SCHEME
RAE LAKES



AVERAGE DAILY FLOWS
DIANA RIVER & GIBSON LAKE

FIGURE 8.2



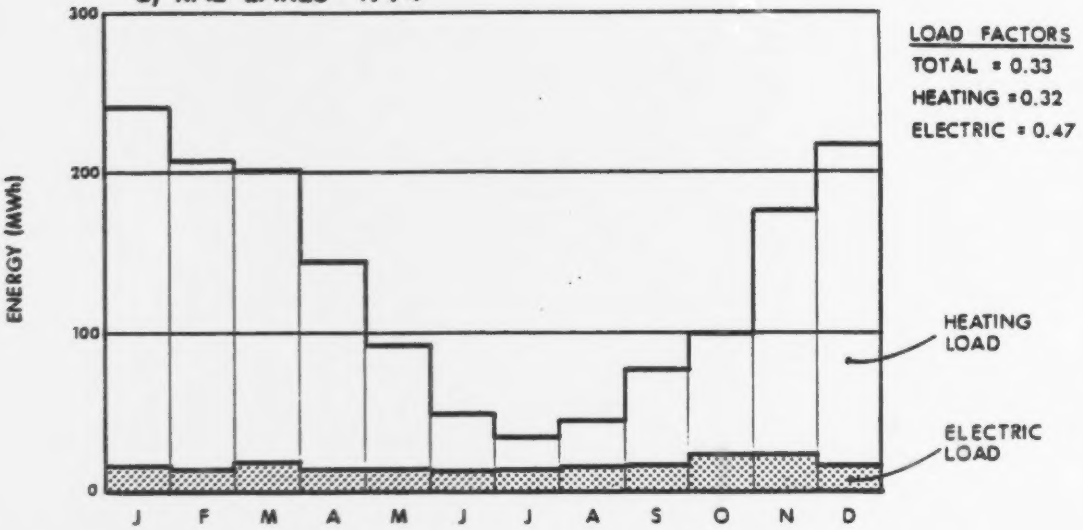
Q_{av} = 25,48 m³/s GIBSON and DIANA

Q_{av} 7,78 m³/s DIANA

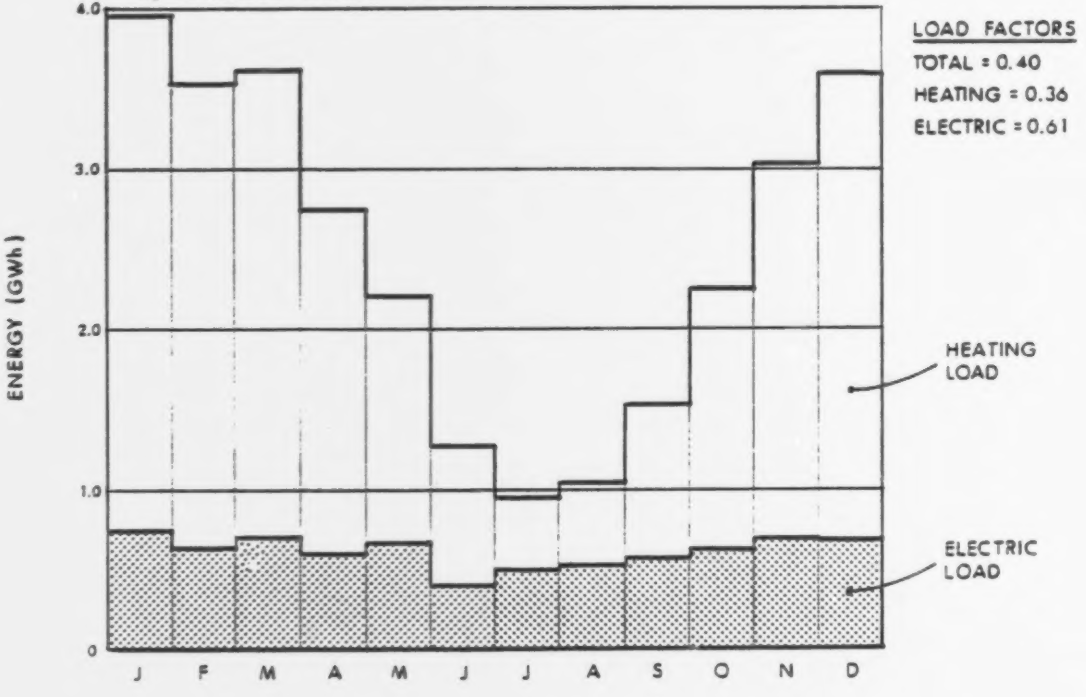
DIMENSIONLESS
DAILY FLOW DURATION CURVE
GIBSON LAKE & DIANA RIVER

FIGURE 8.3

a) RAE LAKES - 1994

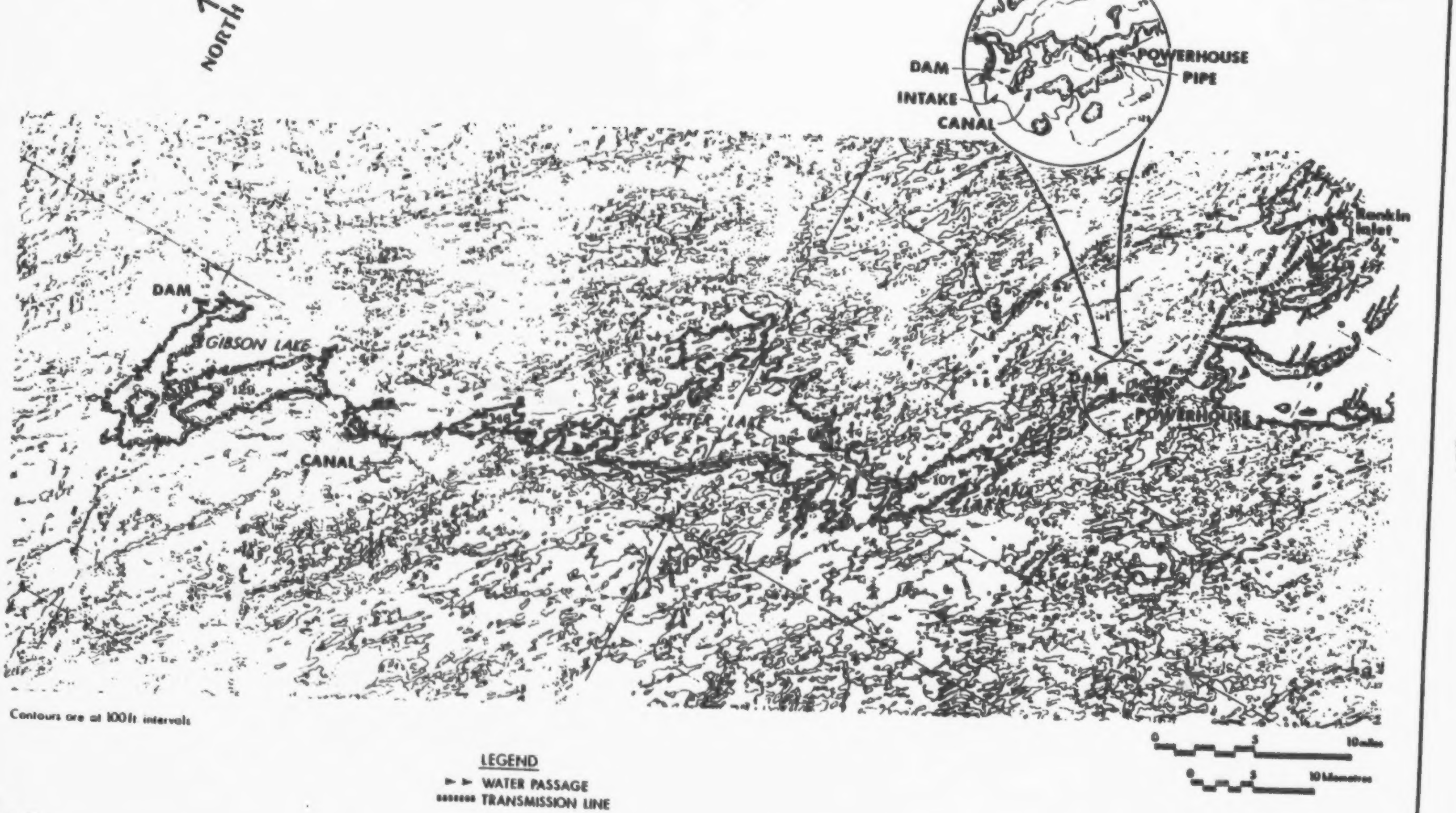


b) RANKIN INLET - 1994



MONTHLY LOADS

FIGURE 8.4


NORTH
DAM
INTAKE
CANAL
POWERHOUSE
PIPE
DAM
GIBSON LAKE
CANAL
PETER LAKE
107
DIANA LAKE
DAM
POWERHOUSE
Rankin Inlet
Contours are at 100 ft intervals
LEGEND
WATER PASSAGE
TRANSMISSION LINE
0
5
10 miles
0
5
10 kilometres

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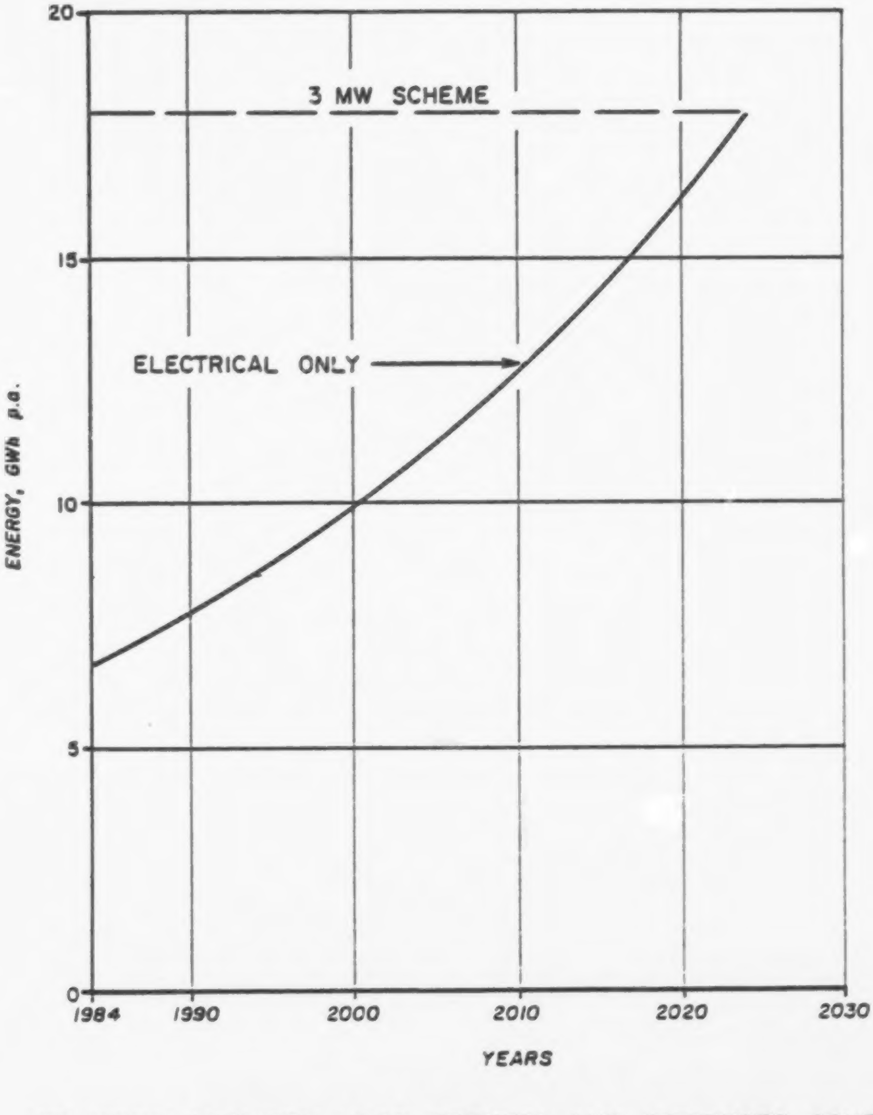
RANKIN INLET
DEVELOPMENT

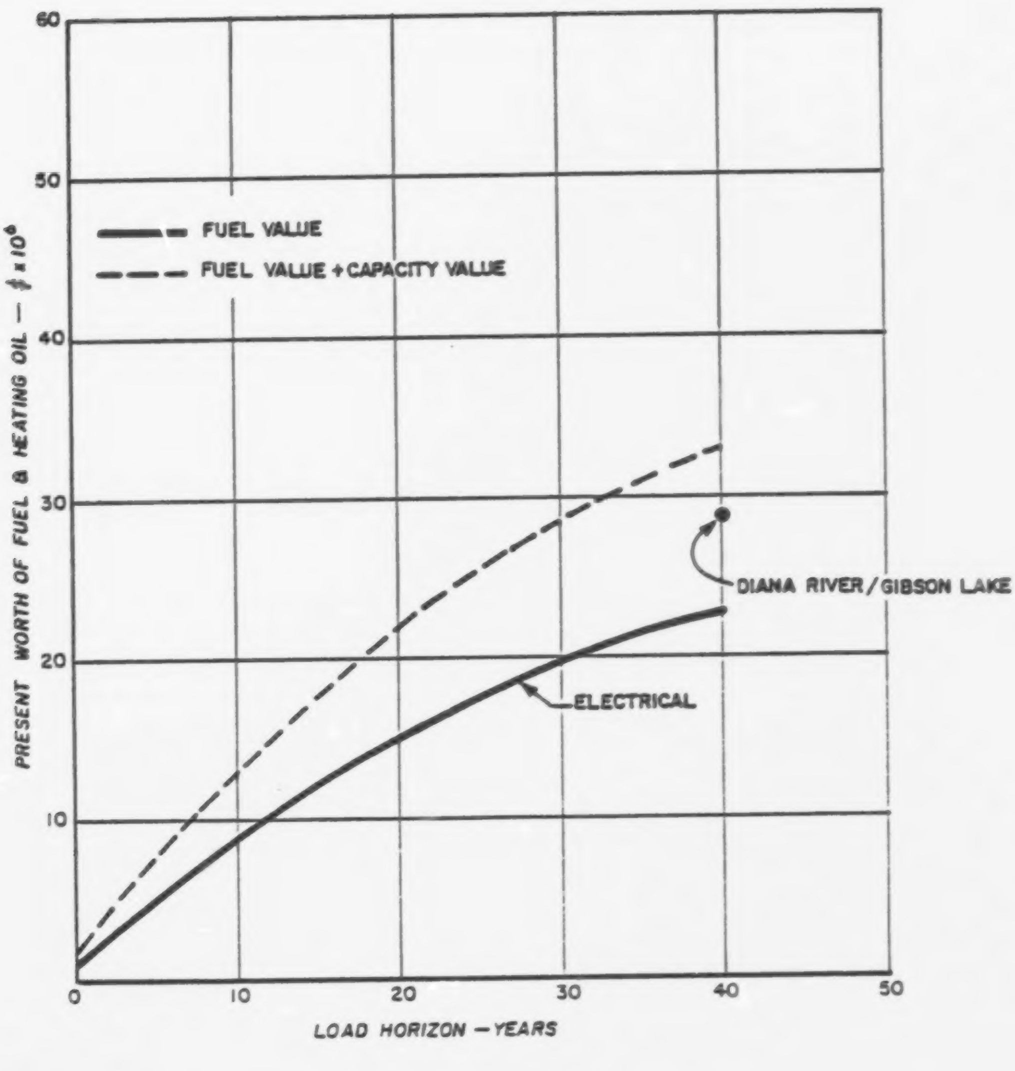
FIGURE 8.5



RELATION BETWEEN LOAD GROWTH AND PROPOSED SCHEME

RANKIN INLET

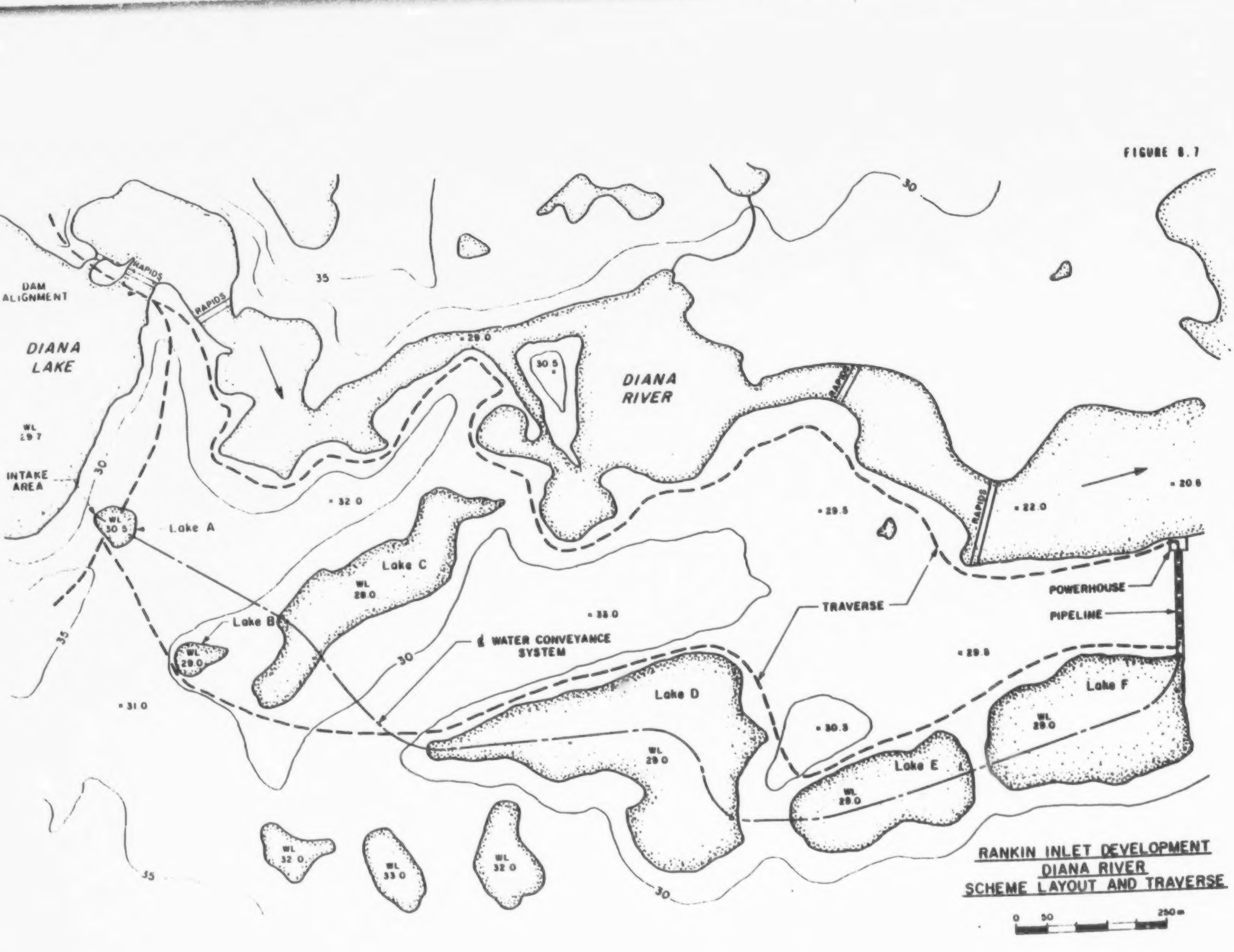
FIGURE 8.6



— PRESENT WORTH OF OIL CONSUMED —

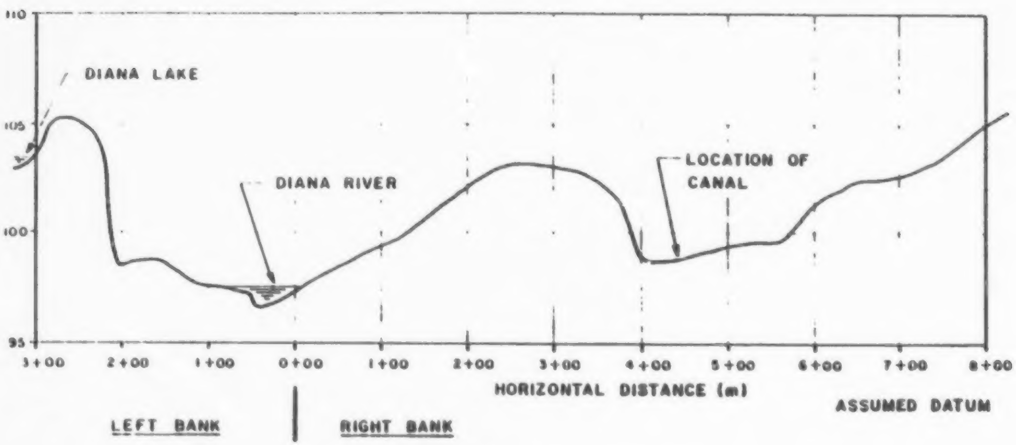
— RANKIN INLET —

FIGURE 8.7

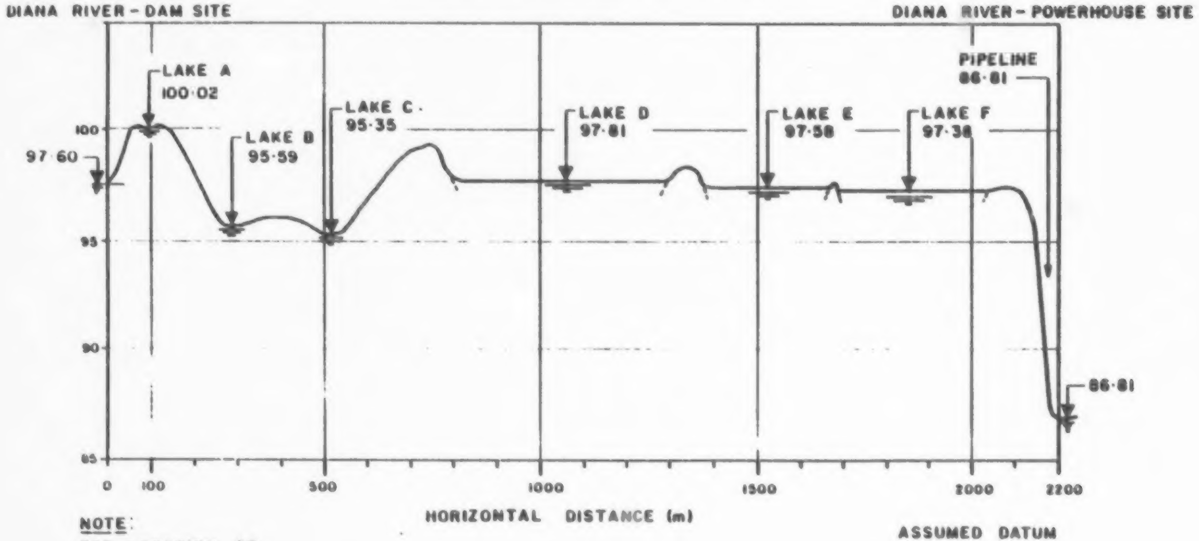

DAM ALIGNMENT
RAPIDS
RAPIDS
35
30
DIANA LAKE
WL 29.7
INTAKE AREA
30
35
WL 30.5
Lake A
• 32.0
• 29.0
30.5
DIANA RIVER
RAPIDS
RAPIDS
• 22.0
• 20.6
• 29.5
Lake C
WL 28.0
Lake B
WL 29.0
• 31.0
• 33.0
℄ WATER CONVEYANCE SYSTEM
30
TRAVERSE
POWERHOUSE
PIPELINE
• 29.5
Lake D
WL 29.0
• 30.3
Lake E
WL 28.0
Lake F
WL 28.0
WL 32.0
WL 33.0
WL 32.0
35
30
0
50
250 m

RANKIN INLET DEVELOPMENT
DIANA RIVER
SCHEME LAYOUT AND TRAVERSE

FIGURE 8 8



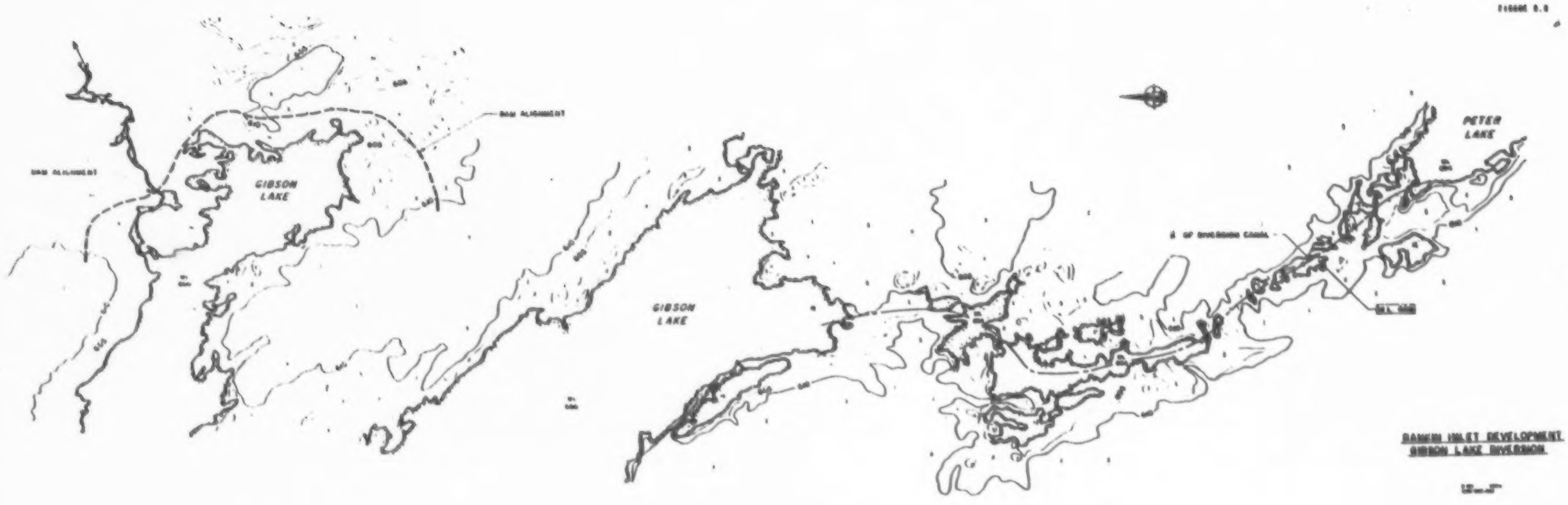
PROFILE ALONG DAM ALIGNMENT



NOTE:
FOR LOCATION OF
LAKES IN PLAN,
SEE FIGURE

PROFILE ALONG WATER CONVEYANCE SYSTEM

RANKIN INLET DEVELOPMENT
PROFILES



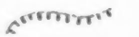
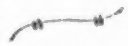
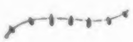
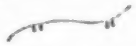
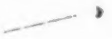
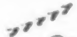
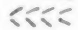
PETER LAKE
GIBSON LAKE
GIBSON LAKE
DAM ALIGNMENT
DAM ALIGNMENT
℄ OF DIVERSION CANAL

RANKIN INLET DEVELOPMENT
GIBSON LAKE DIVERSION

LEGEND FOR BAKER LAKE AND COPPERMINE MAPS

NCPC
LEGEND - SMALL HYDRO SITES

Origin	Map Symbol	Terrain Type	Soil or Rock Description	Landform Characteristics Thickness*	 Topography	Slope*	Surface Drainage and Groundwater	Comments
Glaciofluvial	Gb	Glaciofluvial Blanket	Sand and gravel	1-5 m	Flat to rolling	<3°-5°	Good	Source of granular material
Glaciofluvial	Gr	Glaciofluvial Ridge	Sand and gravel	>5 m	Ridged	5°-45°	Good	Source of granular material
Glaciofluvial	Gt	Glaciofluvial Terrace	Sand and gravel	>5 m	Flat	<3°	Fair to good	Source of granular material
Morainal	Mv	Moraine Veneer	Till--(a) silty clay till in Trout Lake; Trout River; (b) gravelly sand till at other sites	<1 m	Reflects underlying topography Reflects underlying topography	Up to 15° Up to 15°		
Morainal	Mb	Moraine Blanket	Till--(a) silty clay till in Trout Lake; Trout River; (b) gravelly sand till at other sites	1-5 m	Reflects underlying topography Reflects underlying topography	Up to 15° Up to 15°		
Morainal	Mp	Moraine Plain	Till--(a) silty clay till in Trout Lake; Trout River; (b) gravelly sand till at other sites	>5 m	Flat to undulating	3°-5°		
Morainal	Mm	Rolling Moraine	Till--(a) silty clay till in Trout Lake; Trout River; (b) gravelly sand till at other sites	>5 m	Undulating to rolling	5°-9°		
Morainal	Mr	Moraine Ridge	Till--(a) silty clay till in Trout Lake; Trout River; (b) gravelly sand till at other sites	>5 m	Ridge	5°-40°		
Rock	R	Bedrock -	(g) granite (b) basalt (gb) gabbro (ss) sandstone (d) dolomite (sh) shale					

Symbols	
	escarpment
	depositional beach ridge - glacial lake origin
	depositional beach - marine origin
	erosional beach - marine origin
	direction of flow in old meltwater channel
	esker
	ribbed moraine
	crevasse fillings
	drumlinoid moraine

Textural

g - gravel
s - sand
si - silt
c - clay
f - silt and clay
t - silty clay till
$\underline{t}$ - gravelly sandy till

Process

C - channeled
E - eroded, many closely spaced channels
TK - thermokarst
SF - solifluction

*Needs field checking for slopes, thicknesses

Examples

1) Percentage of Unit

tMp / gR ↑ 85% ↑ 0-15%

tMp - gR ↑ 50% ↑ 50%

2) Veneer of Unit Over Another Unit

$\underline{\underline{t}}$Mv ←—— (gravelly till) moraine veneer

gR ←—— overlying granite

3) Processes Affecting Unit

s , f ↑ sandy and fine grained

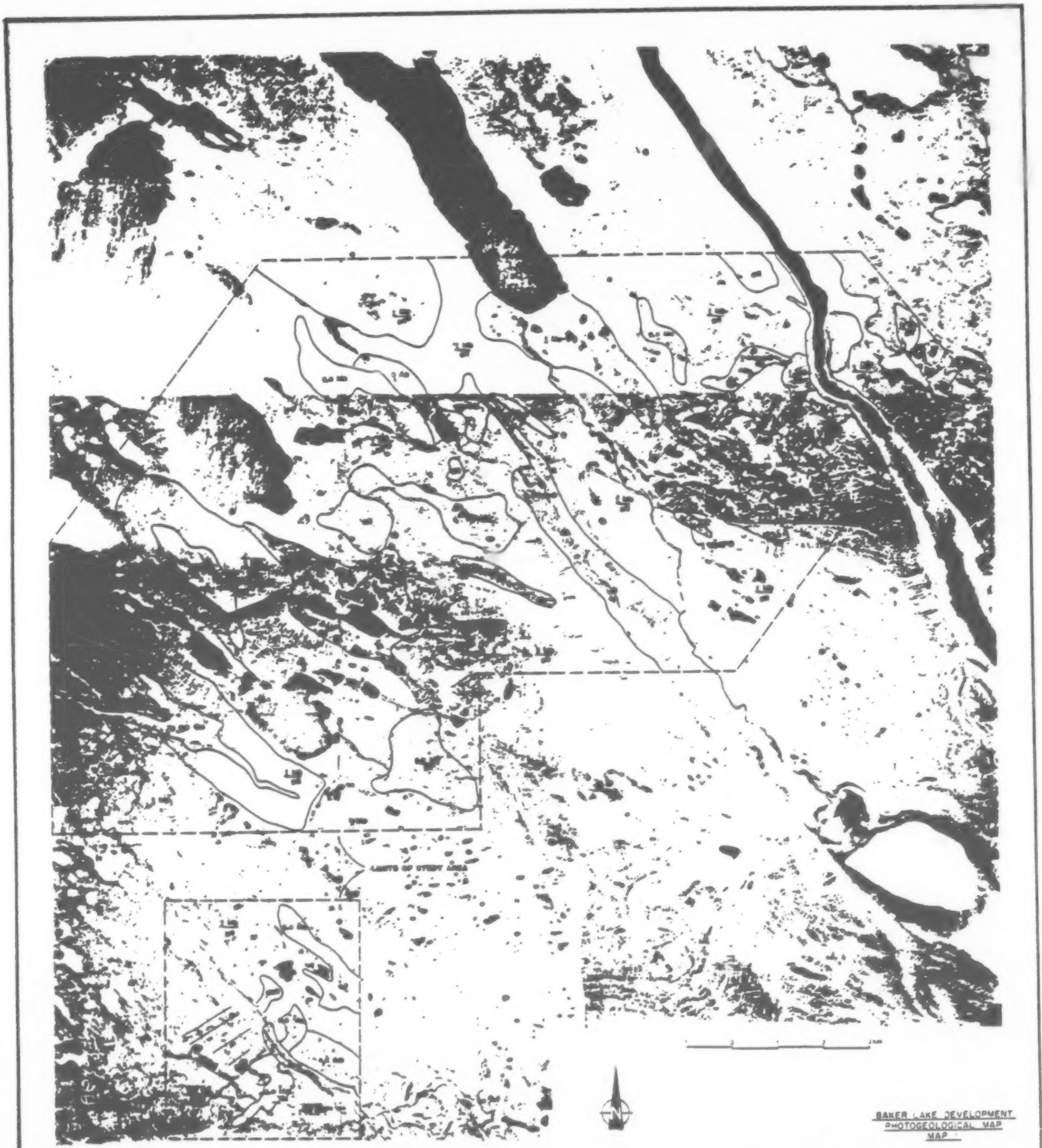
Mp ↑ marine plain

- TK ↑ thermokarst

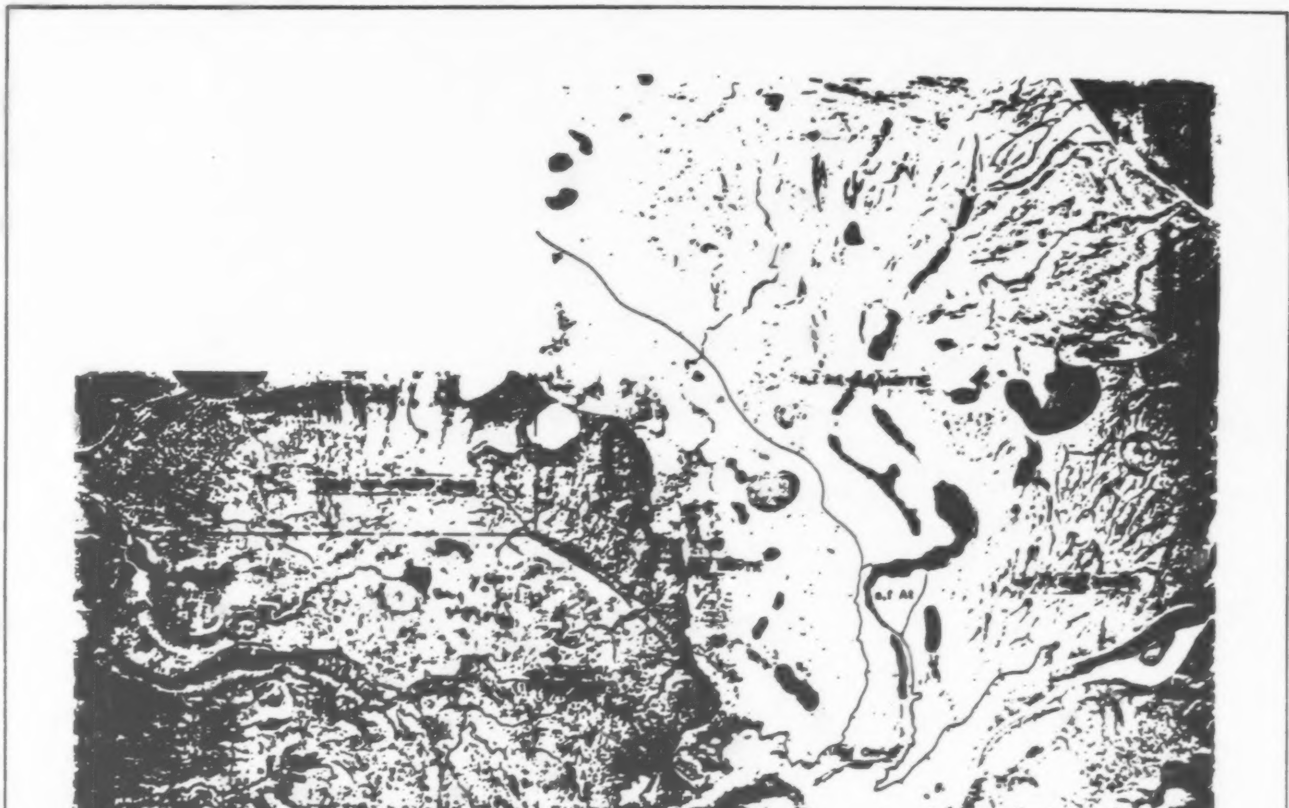
LEGEND FOR BAKER LAKE AND COPPERMINE MAPS

NCPC
LEGEND - SMALL HYDRO SITES

Origin	Map Symbol	Terrain Type	Soil or Rock Description	Landform Characteristics: Thickness*	Landform Characteristics: Topography	Slope*	Surface Drainage and Groundwater	Comments
Organic	FOv	Fen Veneer	Fen	<1 m	Flat to depressional (may reflect underlying material)	<3°	Poor drainage, standing water	Wet ground surface
Organic	FOb	Fen Blanket	Fen	1-2 m	Flat to depressional (may reflect underlying material)	<3°	Poor drainage, standing water	Wet ground surface
Organic	FO	Fen (thick)	Fen	2-3 m	Flat to depressional (may reflect underlying material).	<3°	Poor drainage, standing water	Wet ground surface, may have shallow permafrost
Organic	pOv	Peat Veneer	Peat	<1 m	Flat to depressional	<3°	Poor drainage	Wet ground surface, shallow permafrost
Organic	pOb	Peat Blanket	Peat	1-2 m	Flat to depressional	<3°	Poor drainage	Wet ground surface, shallow permafrost
Organic	pO	Peat (thick)	Peat	2-3 m	Flat to depressional	<3°	Poor drainage	Wet ground surface, shallow permafrost
Organic	pOK	Peat (thick)	Peat	3 m	Rolling	<3°-5°	Poor drainage	Thick permafrost
Colluvial	Cv	Colluvial Veneer	Predominantly silt, clay, sand; some gravel & bedrock debris	<1 m	Gently to steeply sloping (reflects underlying unit)	3-40°	Good drainage	Probably underlain by shallow bedrock
Colluvial	Cb	Colluvial Blanket	Predominantly silt, clay, sand; some gravel & bedrock debris	1-5 m	Gently to steeply sloping (reflects underlying unit)	3-40°	Good drainage	Probably underlain by shallow bedrock; solifluction features.
Colluvial	Cm	Colluvial Mantle	Predominantly silt, clay, sand; some gravel & bedrock debris	>5 m	Gently to steeply sloping	3-40°	Good drainage	Unstable slopes may be present in this terrain unit; solifluction features
Alluvial	Av	Alluvial Veneer	Sand and silt; some gravel	<1 m	Reflects underlying topography	<3°	Good drainage	
Alluvial	Ap	Alluvial Plain	Sand and silt; some gravel	>5 m	Flat to gently undulating	<3°	Good drainage; high water table	Probably unfrozen
Alluvial	At	Alluvial Terrace	Sand and silt; some gravel	>5 m	Flat to gently undulating	<3°	Good drainage; high water table	
Alluvial	Ad$_1$	Alluvial Delta	Sand and silt; some gravel	>5 m	Flat to gently undulating	<3°	Good drainage	
Alluvial	Ad$_2$	Alluvial Delta (youngest)	Sand and silt; some gravel	>5 m	Flat to gently undulating	<3°		
Alluvial; Marine	Am	Alluvial; Marine Plain	Sand; some fines	>5 m	Flat to gently undulating	<3°	Fair to good	
Marine	Mn	Marine Nearshore	Sand	>5 m	Flat to ridged	3-15°	Good	
Marine	Mp	Marine Plain	Sand, fines	1-5 m	Flat to rolling	3-5°	Fair to good	Permafrost in fine grained sediments
Glaciolacustrine	Lv	Glaciolacustrine Veneer	Sand, silt, clay	<1 m	Reflects underlying topography	<3°	Fair to poor; standing water in depressions	Organics and permafrost
Glaciolacustrine	Lp	Glaciolacustrine Plain	Sand, silt, clay	>5 m	Flat	<3°	Fair to poor; standing water in depressions	Organics and permafrost
Glaciolacustrine	Lpbc	Glaciolacustrine Beach Complex	Sand, some gravel	>5 m	Flat to ridged	>3° to 35°	Fair to good on ridges; poor between ridges	Permafrost in fine sediments between ridges


LIMITS OF STUDY AREA
BAKER LAKE DEVELOPMENT
PHOTOGEOLOGICAL MAP
MAP

See pages 234-5 for map legend.


a.f At
1 0 1 2 3km
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COPPERMINE DEVELOPMENT
PHOTOGEOLOGICAL MAP
MAP 2

See pages 234-5 for map legend.

VOLUME II -

AN INVESTIGATION INTO THE COPPERMINE DEVELOPMENT

SECTION 1 - INTRODUCTION

This Appendix Report "Coppermine Development" is part of the Final Report and essentially addresses in detail revised Tasks Eleven and Twelve (b). These revised Tasks are repeated below:

REVISED TASK ELEVEN

Based on the findings of the second Milestone Report and the assessment of those findings by the Management Committee, the Bloody Falls site, Coppermine River, is to be redesigned as a run-of-the-river hydroelectric plant with no dam placed across the river. The detailed layout and design of the project is to be taken to a prefeasibility level and a range of plant capacities is to be investigated. The smallest plant capacity must be capable of satisfying the normal electric load as given by the load forecasts of Task 3. The design will include:

- layout;
- type and size of mechanical and electrical equipment;
- estimate of all civil engineering quantities;
- detailed cost estimate of all civil, electrical and mechanical works with allowances for contingencies, engineering and interest during construction. A total project cost, in 1984 dollars, for the most suitable plant is to be identified;
- construction schedule.

REVISED TASK TWELVE

A final report is to be prepared covering:

a) the merits of the small hydro plants which were investigated as a means of meeting the energy needs of the communities;

b) recommendations and guidelines for the implementation of the Bloody Falls hydroelectric project, if proven to be economically viable;

c) the use of wind as an alternative energy source for each community.

A separate report, in summary form and suitably written for the use of the communities, is also to be prepared.

SECTION 2 - PROJECT AREA

2.1 GEOGRAPHY

Coppermine is the most northerly of the six communities and is located at 67°-50'N latitude, 115°-05'W longitude, and thus lies north of the Arctic circle - 66°-30'N. It is located at the mouth of the Coppermine River on the northern coastline of the Canadian mainland where the Coppermine River empties into Coronation Gulf. This Inuit community was named by the Hudson Bay Company which sent explorers from Fort Prince of Wales to find the source of native copper brought to the fort - hence the inhabitants of Coppermine were called "Copper Inuit".

The communities are located north of the tree line and in a zone of continuous permafrost, Figure A - 2.1. Beyond the tree line the vegetation in these areas is of the tundra type, namely, lichens, mosses, sedges, herbs and dwarf species of alder, birch and willow.

Temperatures at Coppermine are below freezing for eight months of the year and the average monthly temperatures and degree-days are as follows:

Month	°C	°C-days
January	- 30,1	1492
February	- 31,1	1375
March	- 27,1	1399
April	- 17,5	1065
May	- 5,3	723
June	3,8	426
July	9,7	258
August	8,7	289
September	2,5	465
October	- 6,6	763
November	- 19,7	1131
December	- 25,9	1361

Because of the northerly location of Coppermine, there is a great variation in daylight hours. This variation is from zero to 24 hours, as Figure A - 2.2 shows. The occurence of daylight hours together with the temperature affects all construction programmes in the area.

2.2 SOCIO-ECONOMIC ASPECTS

.1 Population

The 1981 population of Coppermine, as recorded by Statistics Canada, was 809 of which 750 were Inuit. The Inuit form the predominant cultural group and there is an even balance between male and female. The largest age cohort groups were found between the ages of 0 and 24 in 1981. Recent statistics would suggest that the Coppermine population is growing at a rate of 3.1% p.a. It is therefore estimated that in 1984 there are 890 people living in Coppermine. The estimated number of people between the ages of 15 and 64 in Coppermine today is 530 split evenly between male and female.

.2 Employment and Income

The economic base of Coppermine is largely traditional, although some members of the community have become involved with offshore exploration for oil and gas in the Beaufort Sea. Echo Bay at Lupin also provides employment for members of the community. Artic char, seals and caribou are harvested along with polar bear, musk-ox and small game. Tourism depends mostly upon the sale of arts and crafts, char fishing and the fact that Coppermine is the terminus of canoeing expeditions on the Coppermine River. Mineral potential of the area consists of gold, uranium, iron, zinc, lead, silver, cobalt, nickel and, of course, copper.

A rough estimate of present employment is given below:

Government (GNWT/Hamlet)	38
Oil and Gas	32
Mining	12
Retail	18
Utilities	2
Transportation	2
Service	6
Construction	14
Hunters/Trappers/Fishermen	
- Full time	5
- Part time (seasonal)	60
Total	189

With an estimated labour force of 375 people, the unemployment rate is roughly 50%. Per capita income in 1981 was recorded at $4 400 and consumer prices were 70%-80% higher than those in Edmonton (1983).

.3 Housing

Housing is exclusively single family in nature. Many different repetitive housing designs have been used over the years with varying degrees of success. Some of the older houses are now being rehabilitated. In 1983 the NWT Housing Corporation maintained 168 single family units, GNWT 17 units, and the Federal Government 10. New units which are under construction in 1984 include singles and one structure with nine adjoining units. Heating is by means of fuel oil supplied by POL and the Co-op.

.4 Commercial

Retail and wholesale trade is very limited with retail goods being supplied by the Bay and the Co-op. The Igloo Inn provides accommodation for 40 persons and also operates a dining room. Arts and crafts include articles made from caribou bone, copper artifacts, soapstone carvings and "Mother Hubbard" parkas.

.5 Industrial

There are virtually no industries other than two small local contractors.

.6 Recreation

The Coppermine Recreation Centre consists of a large hall with a stage and an ice arena. The community also has a playground, school gym and a sports field.

.7 Social Services

The community has a school which provides education from kindergarten to grade 9, and which had a 1983/84 enrollment of 226 students. The school year starts the 2nd week in August and ends the first week in June.

There is a four bed, one bassinet nursing station staffed by three nurses and a visiting doctor. Two people staff the community Social Services Office and there is a Coppermine Alcohol Committee. The religious needs of the community are served by the Anglican, Pentecostal and Roman Catholic churches.

A police force of 3 people is stationed in Coppermine along with Justices of the Peace and a coroner. Fire protection is provided by a 15 person volunteer fire brigade. Water is supplied by an 800 gallon fire truck. The fire alarm system consists of call boxes throughout the community and are connected to a siren.

.8 Transportation

Coppermine has a 1 520 m gravel landing strip with runway lighting. The airport facilities include a small terminal building, rotating beacon, wind socks, a directional beacon and a fuel depot. The community is served by Northwest Territorial Airways which operates a scheduled air service between Coppermine and Yellowknife.

A float plane base, with no refueling services, exists along the waterfront. This base is usually used between mid-July and mid-September.

Barge service is available for community re-supply of bulk items such as fuel which originate out of Hay river.

Surface transportation is available through a taxi within the Community. There is also a growing number of motorised, three wheeled cycles in the community. There are no roads or highways external to the community.

.9 Water, Sewer, Roads, Solid Waste

Water is drawn from the Coppermine river and chlorinated. Since the treatment excludes the use of settling tanks, the water supply contains sediments during the spring runoff. There is an intake and limited pipe distribution system. However, salt water intrusion into the intake has been a problem and the pipe distribution system is no longer in use. Water is truck delivered about 1-2 times per week.

Sanitation is provided mainly by a pump out truck which empties sewage holding tanks once or twice per week and disposes the contents at the solid waste area located between the airstrip and the Coronation Gulf. Some areas of the community, including the hotel, utilize bagged sewage. This waste is picked up daily and disposed in the solid waste area. Solid wastes are placed in steel barrels at the roadside and are picked up three times per week.

Gravel roads have been built in the community over the rocky terrain. Drainage is provided by means of open ditches and specially built swales which include vertical rip-rap to prevent sloughing due to melting of the permafrost.

.10 Lifestyle

The lifestyle in the community may be described as Inuit traditional with a gradual change toward increasing wage employment and social assistance. Recent wage employment other than government has been provided by the non-renewable resource sectors of oil and gas and mining.

The importance of traditional pursuits in the community is highlighted in Table A - 2.1, below. These figures must be considered conservative since they are only based on approximately one year of data, one month being missing, and with only 50% of the hunters reporting.

TABLE A - 2.1

Estimated Coppermine Harvest (1983)

Species	No.	Estimated Avg. Edible Weight (kg)/Species	Total Est. Edible Weight Available Each Year (kg)	%
Caribou	1 270	48	60 960	54
Seals	549	14	7 690	7
Char	8 531	2,5	21 330	19
Whitefish	5 188	2,8	14 530	13
Trout	1 756	2,4	4 210	4
Musk-Ox	18	110	1 980	2
Moose	7	199	1 390	1
Wolves	49	-	-	-
Wolverine	64	-	-	-
Arctic Hares	89	2,3	200	-
Ptarmigan	477	0,4	190	-
Ducks	562	0,7	390	-
Geese	191	2,4	460	-
		Total	113 330	100

Source: GNWT - Renewable Resources

Note: Reporting rate - 50%

To replace the total amount (113 300 kg) of meat/fish with say beef at $10/kg would represent 1.1 million dollars annually or $5 600 per household. In percentage terms, this shows that the migrating fish of char and whitefish account for about one-third of the total diet. The domestic fishery could therefore represent one-third or $1 900/household.

Quite apart from the economics, fishing is an important way of life to the Inuit, and it is done in the bay, around the offshore islands and in the Coppermine river. The domestic fishery provides the occasion to move the family out of the community to summer residences located between the estuary and Bloody Falls; residences consist of both wood cabins and tents. Transportation between these summer residences and the community is by means of boat fitted with on outboard engine.

Trapping is one of the traditional ways of life of the Inuit, and the value of fur harvested for the year 1982/83 was estimated at $67 700.

SECTION 3 - LOAD FORECAST

3.1 GENERAL

3.1.1 Load forecast methodology

The following methodology was used to prepare the load forecast:

- forecast population growth using natural increase as the basis. This is shown on Table A - 3.1, below, to year 1994.
- forecast electrical growth using population forecasts and 1982/83 consumption/capita factors plus capital projects forecast by the Government of the Northwest Territories (GNWT).
- forecast space heating growth using population and household characteristics plus capital projects forecast by the GNWT. Express the space heating growth in electrical energy equivalents using a conversion factor of 7,85 kWh per litre for the present space heating fuel.
- combine the electrical and space heating consumer loads for any given year and increase by a factor 14% to allow for distribution and transmission losses. This gives the generation required at the bus bar of the hydro plant.
- obtain design capacity by using the annual load factor, for the normal electric load, and an allowance for the variation of degree days during the winter for the heating load.

The annual load factor for the normal electric load was based on the historical load, Figure A - 3.1. Since on average January is the coldest month of the year a multiplier of 1,4 was applied to the average January heating load. This multiplier was obtained by multiplying the ratio of the highest number of degree-days in one day in January to the average for one day in January, and the ratio of the highest number of degree-days in January to the average for January.

TABLE A - 3.1

POPULATION FORECAST - COPPERMINE

Year	Population
1982	836
1983	861
1984	887
1985	914
1986	942
1987	970
1988	999
1989	1 029
1990	1 060
1991	1 092
1992	1 125
1993	1 159
1994	1 194

Computer rounding has occurred.

3.1.2 Conservation

.1 General

Considerable interest has been expressed over the past 10 years in the desire to conserve energy due to the increased cost of non-renewable energy supplies. The application of energy conservation measures in Northern Canada has been somewhat slower than in the rest of the country due to the fact that the ultimate consumer of energy in many cases is shielded from paying the full cost. Recently, efforts have been made to conserve energy in the N.W.T. in the following manner:

- a gradual movement toward a "user pay" position (GNWT)
- notification to consumers of electrical subsidies through split billing by NCPC (GNWT)
- public education programs (GNWT)
- establishment of the Canadian Energy Audit Program (EMR)
- programs established under ENERDEMO eg., Remote Community Demonstration Program (EMR).

Constraints to implementing energy conservation in the N.W.T. include the following:

- hidden subsidies
- ability to pay
- resistance to change.

The impact of conservation upon energy forecasting is related both to typical electrical loads, and space heating.

.2 Electrical

The anticipated effect of conservation in Alberta has been well documented in a study entitled "Alberta Energy and Demand Forecast (1983-2007)" conducted by the Electric Utility Planning Council.

From that study the following may apply to the N.W.T.:

Residential Sector

. The net effect of conservation upon electrical consumption per household will be to dampen the rate of growth of energy consumption;

- a maximum reduction of up to 400 kWh/household/yr is probable as existing refrigerators are replaced by new refrigerators.

Commercial Sector

- Street lighting consumption could be reduced by 50% by substituting high pressure sodium (HPS) lighting for mercury vapour lamps. However, since street lighting is only 1% of total sales, this would result in an overall decrease of ½% in the total demand.

.3 Space Heating

The Northwest Territorial Housing Corporation owns and maintains 85% of the housing at Coppermine. The Corporation is implementing a rehabilitation programme in Coppermine to bring older units up to existing residential standards. In this programme the heating systems are replaced, the insulation of walls, attic and floors is upgraded, and the windows/doors are replaced.

3.1.3 Lifestyle

Changes due to "increases in the standard of living" or "life-style" upon future demand depends on the degree of appliance ownership and the use of electricity for space heating.

Table A - 3.2 below compares the six communities with Inuvik in the domestic sales sector. Domestic sales in each community accounted for approximately one-half of total sales except in Frobisher Bay where it accounted for 40%. The Inuit traditional communities such as Coppermine exhibit a low per capita domestic consumption, but a high per capita consumption growth rate. The Inuit transitional communities such as Frobisher Bay and Rankin Inlet on the other hand, exhibit higher per capita domestic consumption, but a lower per capita consumption growth rate. The degree to which the lifestyle changes in Coppermine will depend upon

- non renewable resource development and the associated Government activity in the area;
- the degree to which the community participates in this development.

TABLE A - 3.2

LIFESTYLE DOMESTIC CONSUMPTION PATTERNS FOR ELECTRICITY

Market	Lifestyle	1981 Domestic Consumption/ Capita (kWh)	Average Annual Growth per capita 1976-1981	1981 Domestic Consumption/ Household (kWh)	1981 Household Size (Persons)
Baker Lake	Inuit Traditional	1 660	6	7 740	4.5
Coppermine	Inuit Traditional	1 420	6.5	6 380	4.5
Fort Simpson	Indian Transitional	2 470	3.5	9 500	3.7
Frobisher Bay	Inuit Transitional	2 770	4.0	10 430	3.6
Rae Lakes	Indian Traditional	570	10.0	3 260	5.7
Rankin Inlet	Inuit Transitional	2 570	4.3	11 630	4.4
Inuvik	Mixed Modern	3 470	2.3	11 820	3.2

3.2 EXISTING ELECTRICAL LOAD

The electrical load in 1982/83 amounted to 2 603 MWh with a peak load of 580 kW and a load factor of 51%. Sales amonted to 2 330 MWh with the domestic market contributing 53%, commercial 46% and street lights accounting for the remainder. There were no wholesale or industrial sales. Average annual growth over the past 6 years has amounted to 6,5%.

Details of generation for the fiscal year 1983/84 are:

	Energy MWh	Peak kW
April, 1983	209,7	480
May	194,0	460
June	157,4	365
July	164,1	385
August	183,7	450
September	203,4	525
October	231,6	540
November	244,2	570
December	279,0	585
January, 1984	292,6	600
February	250,1	620
March	245,4	550
Total	2655,3	

Space heating in Coppermine is supplied by oil furnaces and in 1978/79, 304 583 gallons of heating oil were consumed. This is equivalent to approximately 8 790 MWh of heat as an electrical load. On the basis of sales, this heating load is roughly 4,3 times the electrical load. This was determined by calculating the electrical equivalent of heat and dividing by the present electrical consumption. The electrical equivalent of heat is obtained by converting the heating oil burned to space heat, using an efficiency factor of 60%.

The load shape for both electrical and space heating load for 1994 is shown in Figure A - 3.3. It can be seen that heating is required in each month, but the requirement in summer is small. This could result in the non-utilisation of potential hydro-energy during these months in the initial years of service of the hydro plant.

Details of Generating Units at Coppermine

Type	Output (kW)	Year of installation
Mirrlees EV 6	200	1967
Mirrlees EV 6	200	1967
Mirrlees EV 6	200	1967
Mirrlees EV 8	375	1973
Caterpillar D398	600	1976

3.3 FUTURE LOAD

Considerations of the socio-economic base of the communities and uncertainties regarding future development in the areas led to the detailed analysis of the load only to year 1994. The load from 1994 to 2030, the latter year corresponding to a 40 year economic life of the hydro project, was assumed to increase at a rate of 2% p.a. It was assumed that the earliest date of commissioning of the hydro plant was year 1990.

Load forecasts were prepared to take into account a number of load scenarios. These scenarios are described below and they give rise to a range of forecasts or "family of curves" for designing the electrical supply system. The various loads which were examined were:

Base Electric Load	-	Present electrical load consumption increased by population growth with no increase in per capita consumption, no conservation but an allowance for institutional growth.
Low Electric Load	-	Base Electric Load with an allowance for conservation.
Low Combined Load	-	Low Electric Load + heating load + heating conservation.
Medium Combined Load	-	Base Electric Load + Increased per capita consumption due to lifestyle + heating + conservation (electric + heating)
High Combined Load	-	Base Electric Load + Increased per capita consumption due to lifestyle + heating + NO conservation.

In preparing the forecasts, consideration was taken of the consumer classes, the effects of energy conservation and improved lifestyle in the communities. These two factors have opposing effects on the load demand, but the reduction in energy through conservation, especially in heating energy, far outweighs any increase attributable to improved lifestyle.

Savings in energy resulting from conservation measures for electrical and space heating savings were taken to be:

Electrical	-	20% reduction by 1994 based upon present comparison of government and non-government domestic consumption per customer in Coppermine.
Space Heating	-	20% reduction by 1994 based upon better insulation through retrofits by the N.W.T. Housing Corporation, public education, and from conservation experiences in other developed areas in the Northwest Territories.

Increases in the normal electric load due to improved lifestyles were based on the recorded load growth, development possibilities and a comparison of energy used in other developed areas in the Northwest Territories.

The future domestic consumption in Coppermine was calculated by applying the population forecast (Table A-3.1) against per capita consumption which grows at the historic (1976-1981) annual growth rate of 6,5% from 1420 kWh/capita to a maximum of 2600 kWh/cap. This assumes that residents of Coppermine will continue to participate in regional resource development (petroleum and mining) and achieve similar energy consumption patterns which presently exist in Inuit transitional communities such as Rankin Inlet. Beyond the 2600 kWh/capita threshold, it is assumed that per capita growth rates will reduce to 4% up to the next threshold of 3000 kWh per capita, then 2% thereafter. This is based upon present trends in existing NWT communities as exhibited in Table A-3.2.

It is expected that commercial/institutional electrical consumption will follow population growth at 3% p.a. to 1994, and then reduce to more normal growth rates of 2% p.a. thereafter. These assumptions are summarised as follows:

- 6,5% annual growth in domestic consumption to a maximum of 2600 kWh/capita; then 4,0% to 3000 kWh/capita; then 2,0% thereafter;
- 3,0% annual growth in commercial/institutional consumption to 1994; 2,0% thereafter.

The forecasts are given in Tables A-3.3 to A-3.7 following and they include transmission and distribution losses.

TABLE A - 3.3

LOAD FORECAST - COPPERMINE

	Low Electrical Load		Base Electric Load		Low Combined Load		Medium Combined Load		High Combined Load	
Year	Gen (GWh)	Design (MW)	Gen (GWh)	Design (MW)	Gen (GWh)	Design (MW)	Gen (GWh)	Design (MW)	Gen (GWh)	Design (MW)
1984	2,901	0,66	2,901	0,66	16,415	4,59	16,561	4,62	16,561	4,62
1989	3,026	0,69	3,363	0,76	17,127	4,79	17,641	4,91	19,544	5,44
1994	3,118	0,71	3,898	0,89	17,648	4,94	18,505	5,13	22,918	6,37
1999	3,443	0,78	4,304	0,98	19,485	5,45	20,432	5,67	25,303	7,03
2004	3,802	0,86	4,752	1,08	21,513	6,02	22,558	6,26	27,937	7,76
2009	4,197	0,95	5,247	1,19	23,752	6,64	24,906	6,91	30,844	8,57
2014	4,634	1,05	5,793	1,32	26,225	7,34	27,498	7,63	34,055	9,46
2019	5,117	1,16	6,396	1,46	28,954	8,10	30,360	8,42	37,599	10,45
2024	5,649	1,28	7,061	1,61	31,968	8,94	33,520	9,30	41,513	11,53
2029	6237	1,41	7,796	1,78	35,295	9,87	37,009	10,27	45,834	12,73

TABLE A - 3.4

COPPERMINE

Average Monthly Loads (MWh)

	Low Electric Load			Base Electric Load		
Month	1994	2009	2024	1994	2009	2024
January	330	403	598	413	503	748
February	286	349	519	358	437	649
March	299	364	542	374	456	677
April	255	311	463	319	389	579
May	212	258	384	265	323	480
June	190	231	344	237	289	430
July	190	231	344	237	289	430
August	218	266	395	272	332	494
September	230	281	418	288	351	522
October	265	323	480	331	403	600
November	305	372	553	382	465	691
December	333	406	604	417	508	755
Total	3 118	3 802	5 649	3 898	4 752	7 061

Note: Rounding has occurred.

TABLE A - 3.5

COPPERMINE

Average Monthly Loads (MWh)

Low Combined Load

	1994			2009			2024		
Month	Electric	Heating	Total	Electric	Heating	Total	Electric	Heating	Total
Jan	330	2 019	2 349	445	2 718	3 163	598	3 658	4 256
Feb	287	1 859	2 146	386	2 503	2 889	519	3 368	3 887
Mar	299	1 888	2 187	403	2 542	2 945	542	3 421	3 963
Apr	255	1 438	1 693	344	1 936	2 280	463	3 605	3 068
May	212	973	1 185	285	1 310	1 595	384	1 763	2 147
Jun	190	581	771	256	782	1 038	344	1 052	1 396
Jul	190	348	538	256	469	725	344	631	975
Aug	218	392	610	294	528	822	395	710	1 105
Sept	230	624	854	310	841	1 151	418	1 131	1 549
Oct	265	1 031	1 296	357	1 388	1 745	480	1 868	2 348
Nov	305	1 525	1 830	411	2 053	2 464	553	2 763	3 316
Dec	333	1 845	2 178	449	2 484	2 933	604	3 342	3 946
Total	3 120	14 530	17 650	4 200	19 560	23 760	5 650	26 320	31 970

Note: Rounding has occurred.

TABLE A - 3.6

COPPERMINE

Average Monthly Loads (MWh)

Medium Combined Load

	1994			2009			2024		
Month	Electric	Heating	Total	Electric	Heating	Total	Electric	Heating	Total
Jan	421	2 019	2 440	567	2 718	3 285	763	3 658	4 421
Feb	366	1 859	2 225	492	2 503	2 995	662	3 368	4 030
Mar	382	1 888	2 270	513	2 542	3 055	691	3 421	4 112
Apr	326	1 438	1 764	438	1 936	2 374	590	2 605	3 195
May	270	973	1 243	363	1 310	1 673	489	1 763	2 252
Jun	242	581	823	326	782	1 108	439	1 052	1 491
Jul	242	348	590	326	469	795	439	631	1 070
Aug	278	392	670	374	528	902	504	710	1 214
Sept	294	624	918	395	841	1 236	532	1 131	1 663
Oct	338	1 031	1 369	454	1 388	1 842	612	1 868	2 480
Nov	390	1 525	1 915	524	2 053	2 577	705	2 763	3 468
Dec	425	1 845	2 270	572	2 484	3 056	770	3 342	4 112
Total	3 980	14 530	18 510	5 350	19 560	24 910	7 200	26 320	33 520

Note: Rounding has occurred.

TABLE A - 3.7

COPPERMINE

Average Monthly Loads (MWh)

High Combined Load

	1994			2009			2024		
Month	Electric	Heating	Total	Electric	Heating	Total	Electric	Heating	Total
Jan	504	2 524	3 028	678	3 397	4 075	912	4 573	5 485
Feb	437	2 324	2 761	588	3 128	3 716	792	4 211	5 003
Mar	456	2 360	2 816	614	3 177	3 791	826	4 277	5 103
Apr	390	1 797	2 187	524	2 419	2 943	706	3 257	3 963
May	323	1 216	1 539	435	1 637	2 072	585	2 204	2 789
Jun	290	726	1 016	390	977	1 367	525	1 316	1 841
Jul	290	435	725	390	586	976	525	789	1 314
Aug	333	490	823	448	659	1 107	602	888	1 490
Sept	352	780	1 132	473	1 050	1 523	637	1 414	2 051
Oct	404	1 289	1 693	544	1 735	2 279	731	2 335	3 066
Nov	466	1 906	2 372	627	2 566	3 193	843	3 454	4 297
Dec	509	2 306	2 815	684	3 103	3 787	921	4 178	5 099
Total	4 760	18 160	22 920	6 400	24 440	30 840	8 610	32 900	41 510

Note: Rounding has occurred.

SECTION 4 TOPOGRAPHY

4.1 GENERAL

The project area lies on the Pre-Cambrian shield region which is generally a nearly featureless, rocky plain interspersed with numerous lakes, ridges, hummocks and eskers. In places, the local relief can be quite rugged.

The Coppermine river system is extensive and there are many rapids and falls. In addition, the occurrence of extensive lake systems has the effect of dampening flood peaks, and tends to even out the fluctuations of the annual flows. The lakes also act as traps for sediment derived from the normal erosion processes. These factors are of importance in the production of energy and on the life and maintenance of the turbine runners.

Originally, three areas or sites were examined, namely, Dismal Lakes, Escape Rapids and Bloody Falls. The first two sites were discarded because of the lengthy transmission line which would have been required, and the smaller natural leads which they had in comparison with Bloody Falls. Also, the Dismal Lake site froze during the winter. The Bloody Falls site is shown on Figure A - 4.1.

4.2 DATA BASE

In the first phase of the study the estimation of the head at each of the three sites mentioned was based on topographic maps at a scale of 1:250 000 with 30,48 m (100 ft) or 60,96 m (200 ft) contour. Some 1:50 000 scale maps were also available, but these appeared to be only an enlargement of the 1:250 000 scale map with no real increase in the accuracy of the elevations. The accuracy of head determination, except perhaps the relatively differences between open water bodies, was considered to be ± 15 m (50 ft).

During the second phase, precise levelling was carried out at the Bloody Falls site. This information was later utilised to prepare new maps from existing air photographs; these existing photographs were used to prepare the 1:250 000 scale maps mentioned previously. The scale of the new maps was 1:2500 with 2 m contour intervals.

4.3 FIELD INVESTIGATIONS

The Bloody Falls site was visited on 20 and 21 August, 1984, when the following work was done:

- cross-sections of the Coppermine river were taken in the area of the proposed intake area, just above Bloody Falls, and in the vicinity of the proposed powerhouse, just below the falls. The river sections were obtained by echo sounding and their extensions into the banks by levelling. Six sections were taken upstream of the falls over a distance of 250 m, whilst one section was taken downstream of the falls. The levels were tied to the assumed datum which was used by Water Survey of Canada when a gauging station was established in the area of the headpond on July 19, 1983. The cross-sections are shown on Figure A - 4.2;

- four flow measurements which have been taken to date by Water Survey of Canada at the gauging station, and the preliminary rating curve for the station were obtained from Water Survey of Canada's office at Yellowknife;

- the head difference between the water levels upstream and downstream of the falls was obtained through a closed traverse. The gross head at the falls was found to be 6,33 m when the flow was about 700 m^3/s;

- an aerial reconnaissance of the area between Bloody Falls and Escape Rapids was done. This reconnaissance, together with inspection of the ground material, confirmed the availability of construction material close to the proposed dam site and primarily from a terrace on the left bank of the river. The aerial reconnaissance also confirmed the preliminary findings of the photo-geological interpretation of the project area. These preliminary findings were made in the second phase of the Study.

- examination of the area in the immediate vicinity of the falls confirmed that the selection of the proposed tunnel alignment on the left bank was preferable to one on the right bank. However, the granitic rocks along the tunnel alignment appeared to be quite blocky, but the extent of the numerous joints into the exposed rock was uncertain. Near the proposed tunnel alignment there is a perched lake, and this would suggest that the joints do not extend deeply into the rock, or that the frozen overburden prevents infiltration.

The general impression of the Bloody Falls site was that it appeared to be present favourable geotechnical characteristics and had enough potential to supply the local energy needs. From a technical viewpoint it should present little difficulty in constructing the proposed low head hydroelectric development. The Escape Rapids site, which was suggested in other studies, has a smaller head concentration, quite apart from the greater transmission distance required to Coppermine. In these respects it is quite an inferior alternative.

The field visit also brought out the fact that a great deal of fishing is done by the local community as far up river as the downstream end of Bloody Falls. The passage of fish across the falls seem to be confined to two channels, one of which was located near the left bank of the river and the other near the right bank.

4.4 HEAD

The evaluation of the power and energy potential and the economic evaluation of each site is dependent on a reasonable estimate of the available head. In addition, it is necessary to have rating curves at the intake and tailrace areas. These curves were used to design the cofferdams, establish critical levels for the intake and powerhouse, and for the setting of the turbine.

Figure A - 4.3 shows preliminary rating curves which have been prepared from a combination of the data collected from Water Survey of Canada and a theoretical consideration. The [illegible]stream curve is based on theory and the fact that the elevation difference between the river levels immediately upstream and down[illegible] the falls was measured to be 6,33 m when the flow was about 700 m³/s.

SECTION 5 - HYDROLOGY

5.1 DATA BASE

Until 1983 the Coppermine river was gauged only at the outlet of Point Lake in the upper reach of the drainage basin. In 1983 Water Survey of Canada erected a gauging station just upstream of Bloody Falls. The flow measurements which have been taken so far are compared below with the corresponding flows at the gauging station at the outlet of Point Lake, Coppermine river.

Date	Flows - m^3/s Bloody Falls	 Point Lake
1983		
19 July	707	231
5 August	494	260
9 September	1 006	232
1984		
26 March	105	48 *
10 August	686	336

* Estimated from the recession curve of average flow conditions at Point Lake.

As the data would seem to suggest, there is a very poor correlation between flows at Point Lake and those at Bloody Falls. This is because of natural regulation at Point Lake and the occurence of so many lakes between the two gauging stations.

As this data was inadequate to estimate the flows at Bloody Falls, a regional approach was adopted. The additional data which was used was:

- recorded flows from 14 gauging stations operated by Water Survey of Canada. These stations together with their drainage area, specific yield and period of record are given in Table A - 5.1;

TABLE A - 5.1

GAUGING STATIONS USED IN STUDY

Gauge No.	Gauge Location	Period of Record	Drainage Area km2	Specific Yield l/s/km2
10JA002	Camsell River at Outlet of Clut Lake	33#, 34-35C, 63-64S, 65-82C	31 100	2.77
10PB001	Coppermine River at Outlet of Point Lake	64#, 65-82C	20 300	5.21
06LC001	Kazan River above Kazan Falls	60-64#, 65-70C, 71S, 72-82C	72 300	5.90
06LA001	Kazan River at Outlet of Ennadai Lake	62-63S, 64#, 65S, 67-78C, 79S, 80-82C	23 900	5.03
06MA002	Kitiyouuq Creek near Baker Lake	69-78C, 79-80S, 81-82C	433	5.73
10ED002	Liard River near the Mouth	72-82C	277 000	*
06MB001	Quoich River above St. Clair Falls	69-71#, 72-79C, 80#, 81-82C	28 700	5.34
10EC001	South Nahanni River above Clausen Creek	59-62S, 63-81C	33 400	*
10TE001	Sylvia Grinnell River near Frobisher Bay	71C, 72-82S	3 030	8.87 +
06MA003	Thelon River above Baker Lake	73-78C, 79S, 80-82C	154 000	4.64
10JC002	Thelon River above Beverly Lake	65-69#, 70-71S, 72-74C, 75-79S, 80-82C	65 300	*
10QA001	Tree River near the Mouth	69-82C	5 960	*
10FA002	Trout River at Fort Simpson Hwy.	69-82C	9 090	3.51
10GB001	Willow Lake River near the Mouth	64-82C	21 600	*

Legend

# - Miscellaneous recordings 33 = 1933 etc.
C - Continuous recording
S - Seasonal recording
* - Used for flood forecast only. Specific yield not calculated
+ - Based on one complete year of record (1971)

Source

Environment Canada, Water Survey of Canada
Reference Index, 1981 and Record Data Tapes 1984

- the hydrologic atlas of Canada;
- two previous engineering studies of the Northwest Territories, References 7 and 12.

5.2 CLIMATE

Climate plays a decisive role in the life of the Inuit, in geomorphological processes, and in the design and construction methods for projects in the northern latitudes. The key determinant of the climatic condition is the amount of incoming solar radiation, which decreases as latitude increases; the climatic classification of the Coppermine area is tundra type. Because of the northerly location of the areas, there is a great variation in the daylight hours as the year progresses, Figure A - 2.2.

The project areas lie in region where the mean monthly temperature varies from -30,1°C in January to 9,7°C in July. The average temperature of the area is below freezing for 8 months of the year.

As can be seen in Figure A - 2.1, continuous permafrost is found in the project area. The occurrence of permafrost has a distinct and severe effect on the design criteria and construction methods which must be adopted. Figure A -2.1 also indicates the location of the tree line which has an effect on the amount of evapotranspirational loss.

The magnitude of the average annual wind speed at Coppermine is about 16 km/hr.

5.3 PRECIPITATION

During the eight months of winter, surges of cold, arctic air flow southwards with the accompanying low temperatures. The ability of the air to contain moisture at such low temperatures is very small and very little precipitation can occur under these circumstances. Most of the winter accumulation occurs when the moist air flows from the southerly direction. Figure A - 5.1 shows that the amount of precipitation in the mainland region of the Northwest Territories varies from about 150 mm per annum to about 300 mm p.a. The greater amount of precipitation in the Frobisher Bay area is due to its location, namely, facing Frobisher Bay and the Atlantic Ocean, and hence there is a greater occurrence of the interaction of moisture laden air from the south with the cold, arctic, air from the north. The data for Figure A - 5.1 was obtained from Reference 7.

5.4 EVAPOTRANSPIRATION

Evaporation and evapotranspiration in the study are quite small and this is indicated in Figure A - 5.2. The low evaporation is due to the long winters, small amounts of solar radiation, low temperatures and ice cover on the rivers and numerous lakes. The date of Figure A - 5.2 was obtained from Reference 12.

5.5 RUNOFF

Of the six study areas, only one did not have a streamgauging station on the associated river or on a nearby river. For the remaining rivers although there was a streamgauging station on the river being investigated, the location of the gauge with long term records was not at the intake site; the gauge upstream of Bloody Falls is just over one year old. Methods were therefore developed to transpose the available data to the intake site.

Extreme patterns of runoff in the region are illustrated by Figures A - 5.3 and A - 5.4 which are dimensionless hydrographs for the Coppermine river at the outlet of Point Lake and the Quoich river above St.Clair Falls. The hydrographs indicate very clearly the effects of the occurrence of lakes, and the period when the rivers could be frozen. Where the lake area is a small portion of the drainage area, the flood peaks and the dimensionless ratio of flow to average flow are high.

Figure A - 5.5 shows a regional runoff map of the area. This map was obtained from Reference 7, and the calculations which were made for its preparation was based on a short period of recorded flow. Up to date, 1982, information of recorded flow was used to check the validity of the isohyds. The check consisted of comparing the flows which should be obtained at established gauging stations, using the isohyds, with the measured flows. The results are as follows:

Gauge	Runnoff - mm		
	Recorded	From Isohyds	Error - %
Camsell River	87,4	80	- 8,5
Coppermine River	164,3	156	- 5,0
Kazan River at Ennadai	158,6	156	- 1,6
Kazan River at Kazan F.	186,1	210	+ 12,9
Kitiyouuq Creek	180,7	170	- 5,9
Quoich River	168,4	156	- 7,4
Thelon River at Baker Lake	146,3	149	+ 1,8
Trout River at Highway	110,7	122	+10,2

The agreement of the isohyds with the recorded flows are considered to be quite good for the study areas. This map was used to check specific yields for ungauged drainage areas.

In order to estimate the flow at an ungaged location, not only the specific yield, but also the shape of the hydrographs must be known. Specific yields of gauged areas, runoff, precipitation, evapotranspiration, and estimated runoff to precipitation ratio were all used to obtain the specific yields for an ungaged location. Estimates of runoff to precipitation were obtained using Figure A - 5.6. This graph was prepared by calculating the average precipitation, from Figure A - 5.1, and runoff, from the recorded daily flows, and plotting the ratio of runoff to precipitation against the latitude of the centre of the drainage basin. The analyses, as outlined above, allowed the adoption of a specific yield of 4,70 $l/s/km^2$ for the Coppermine river at Bloody Falls.

The recorded flows of some of the stations which were examined indicated that many of the rivers froze during the winter. Under the climatic conditions which prevail in the study areas, any lake or river which is less than 2,5 m deep would be frozen to the bottom in the winter. This condition allowed one part of the hydrographs to be plotted.

To plot the location of the peak flow, its time of occurrence was noted from the pattern of the gauged rivers, and from the time of break-up. The value of the peak flow was derived using Figure A - 5.7 which shows the relationship between the ratio of peak flow to average flow and the percentage of lakes occurring in the drainage basin. The area of the lakes were obtained from the available topographic map. A similar relationship is shown in this Figure for the ratio of minimum flow to average flow.

Knowing the peak flow, average flow, based on specific yield - and minimum flow, it was possible to prepare a hydrograph of the ungauged locations.

5.6 PROJECT FLOWS

In making the preliminary estimates of low flows at Bloody Falls during the first phase of this Study, it was assumed that, except for Point Lake, all other lakes and smaller rivers froze during the winter; this is certainly the case for Dismal Lakes. The flow of 105 m^3/s at Bloody Falls on 26 March, 1984, during the period of low flows, indicates that this assumption is not true, and that the minimum flow at Bloody Falls comes from Point Lake and another lake. It would appear from discussions with Water Survey of Canada that there is a winter contribution from Takijuq Lake.

The area of Takijuq Lake is about 35% of the contributing drainage area of 6 800 km^2 and is not far removed from Point Lake. Using Figure A - 5.7, and also an average runoff of 5,21 l/s/km^2, Table A - 5.1 (Point Lake), then the following can be stated:

- ratio of minimum flow to average flow = 0,6
- average flow = 35,43 m^3/s
- hence, minimum flow from Takijuq Lake = 21,2 m^3/s.

Since the minimum recorded flow out of Point Lake is 36,8 m^3/s, then the minimum flow at Bloody Falls should be 58 m^3/s; that is, the sum of the minimum flows from Point Lake and Takijuq Lake. The implicit assumption that the minimum flows from Point Lake and Takijuq Lake are coincident leads to a conservative estimate of the low flow at Bloody Falls.

The drainage area of the Coppermine river at Bloody Falls is about 40,404 km^2 and the average runoff is 191,9 m^3/s for a specific yield of 4,75 l/s/km^2.

To check this estimate of the minimum flow at Bloody Falls, it was assumed that the same ratio of minimum flow to average flow in the Thelon river, Figure A - 5.8, applies to the Coppermine river. This ratio is 0,31, and when it is applied to the average flow of 191,9 m^3/s gave a minimum flow at Bloody Falls of 59,5 m^3/s.

For the purpose of this report, the minimum flow at Bloody Falls has been taken as 58 m^3/s.

The average daily flows and the dimensionless daily flow duration curve for the Coppermine river at Bloody Falls are shown on Figures A - 5.9 and A - 5.10, respectively.

5.7 FLOOD FLOWS

The flood analysis was done using a regional technique consistent with the geomorphologic characteristic of the region. A predominant feature of the study area is the widespread occurrence of lakes which tend to dampen flood peaks and even out river flows.

Data from all of the stream gauges were used in the regional analysis. The maximum annual flood peaks for each of the stations were plotted on a log-normal paper to provide the 1 in 20 year (construction flood) 1 in 100, 1 in 500 and 1 in 1000 year (spillway design flood). Then the values of all the 1 in 20 year etc. floods were plotted against drainage area. It was found that the floods from drainage basins in which major lakes accounted for less than about 15% of the total area tended to group together. Similarly, drainage basins which had major lakes covering more than 15% of the total area formed another group.

The resulting lines of best fit which summarises this situation are shown in Figures A - 5.11 and A - 5.12, and in the following table for the 1:20 year and 1:1000 year floods.

Category	1 in 20 year flood	1 in 1000 year flood
Lakes greater than 15% of the drainage basin	$Q = 0{,}016\ A^{1{,}04}$ $r^2 = 0{,}94$	$Q = 0{,}036\ A^{0{,}99}$ $r^2 = 0{,}94$
Lakes less than 15% of the drainage basin	$Q = 0{,}63\ A^{0{,}81}$ $r^2 = 0{,}94$	$Q = 1{,}41\ A^{0{,}79}$ $r^2 = 0{,}97$

where Q = flood flow in m^3/s
A = area of the drainage basin in km2
r = coefficient of correlation

As can be seen from the results, the coefficient of determination of the relationships is quite high.

The Study reported in Ref. 37 analysed about 50 rivers in the Northwest Territories in an effort to relate floods of 2 year, 10 year and 50 year return periods to channel geometry. The values which were obtained compared well with those obtained by the regional analysis. The graph showing the design floods for the Bloody Falls site are shown on Figure A - 5.13.

SECTION 6 - GEOTECHNICAL

6.1 GENERAL

Bloody Falls is situated in the Coronation Hills physiographic subdivision of the Kazan region. Bedrock is gabbro of the coronation sills and dykes and is Proterozoic age. Downstream from Bloody Falls thick quaternary alluvial deposits of the Coppermine River and post glacial marine deposits representing higher sea levels are present. Tundra ponds cover the surface of this alluvium.

The terrain at the proposed project site is illustrated on the mosaic, Map 1. This mosaic has been terrain-typed in accord with the accompanying legend and shows a wide range of terrain units from Precambrian igneous rock to actively forming delta and alluvial deposits.

At Bloody Falls the Coppermine River is constricted by outcrops of gabbro to form a small lake or reach of comparatively low slope just upstream of the falls. The river is presently forming a delta at the head of this lake (photo 1).

Near surface materials in the vicinity of Bloody Falls and to the north are generally level, flat lying marine plain, deltaic and alluvial deposits. This material, which is 3m to 5+m in thickness, overlies igneous and metasedimentary rock. Exposures along the river banks below the falls confirm that the material is predominantly silt and sand which tends, for the most part, not to be ice rich in exposures. It is therefore stable at comparatively steep slopes. The exception is the reach immediately downstream of the falls along the left bank and along the left bank tributary streams, which exhibit widespread erosion and mass movements commonly associated with thawing, ice rich slopes in silt.

As illustrated on Map 1, the upland west of the proposed headpond is predominantly a thick plain of marine sand and silt. Along the left bank of the river, upstream of the falls, significant segments of the river bank are now at a shallow and stable angle. Along the right bank is an eroded blanket of fine grained colluvium and some alluvial deposits. The falls are constricted by outcrops of deeply jointed overlying metasedimentary rock (photo 3).

6.2 DIVERSION TROUGH

At the location of the proposed intake immediately upstream of the falls, it is anticipated that the diversion trough in the river will have to be excavated in the metasedimentary rock which outcrops at river level on each bank and dips slightly to the northwest. This bedrock is likely covered with a veneer of granular material. The abutments are shallow sloping colluvium which is partially armoured to a height of about 8 m above river level. Above this level the shallow slopes continue with a blanket of vegetated marine material and fine grained colluvium over bedrock. It is evident that stable foundation conditions are present for a structure at this location.

6.3 HEADPOND

As is evident from the mosaic and the field photos, the river banks slopes immediately upstream of the proposed intake are in thick marine sand and silt which are stable at very steep angles (photo 4). In some sections, these materials have eroded along slopes and have formed colluvium which lies at shallow angles. Portions of the river banks in the colluvium are now resting at shallow angles and are not susceptible to further significant movements. As noted earlier, the lower 8 m are largely, stable armoured beaches.

6.4 TUNNEL AND POWERHOUSE

The proposed power tunnel and powerhouse will be excavated through the rock of the left bank from an intake located in or near the metamorphosed siltstone outcrop (photo 3) to the gabbro outcrop near the bottom of the falls (photo 8). The tunnel will be therefore drilled through the highly jointed igneous rock which forms the river banks at the falls. It is possible that this rock will require some structural support, such as rock bolting, to ensure integrity of the tunnel and some form of lining to eliminate seepage; the perched lake (photo 2) lies along the tunnel alignment. On the other hand low ground temperatures (-7°C) may prevent significant leakage. During the field trip in August, surface water was ponded at several points above the rock despite a very thin veneer of tundra. For the prefeasibility study a full concrete lining should be assumed. If the study of the scheme proceeds to feasibility stage, several bore holes should be drilled along the tunnel line to determine the integrity of the bedrock, as well as the temperature and distribution of the ground ice.

6.5 TAILRACE

Excellent foundation conditions appear to be in place at the proposed location of the tailrace. Photo 8 shows the rock in the vecinity of the end of the tailrace tunnel.

6.6 TRANSMISSION LINE ROUTE

Most of the terrain between Bloody Falls and Coppermine is a sandy alluvial delta or sandy marine plain with thermokarst features (Map 1). The surface is level and, exposures along the river bank suggest that the material is not ice-rich, at least along the lower reaches. The terrain is therefore generally stable. Widespread erosion and mass-wasting of thawing slopes is limited to the left bank for a distance of about 2 km downstream of Bloody Falls. These failures extend about 1 km from the river bank and along the tributary ravines. Final routing of a stable transmission line supported by timber poles driven into prethawed pilot holes should not present a problem.

6.7 BORROW SOURCES

The primary source of granular borrow will probably be the terraced esker, immediately downstream of Bloody Falls along the left bank, which may yield an estimated 400 000 m^3 of material. Alternatively, the alluvial terrace on the left bank, 4 km upstream of the falls is a potential source of granular construction material. The terrace must be sampled to confirm grain size distribution, but it would appear to be a good source of sand, gravel and cobbles with a potential volume of about 14×10^6 cubic metres. There are several similar terraces further upstream.

An alternative source of granular material exists in the form of several eskers located 21 km to the east. Exposures of these eskers indicate a good distribution of grain sizes from sand to boulders, and it is expected that the total volume of such material available from this source exceeds 6×10^6 cubic metres.

All of the other construction materials which are likely necessary, ranging from sandy silt to very large angular rock fragments suitable for rip rap, are available within close proximity (approximately 1 km) of the proposed dam site. The silt would come from marine deposits (photo 7) and the rock from talus and outcrops (photo 5) and tunnel excavation. The amount of construction materials which are available is very much in excess of what is required.

SECTION 7 SITE DEVELOPMENT

7.1 SUMMARY OF EARLY WORK

During the first phase of the study, three possible sites for developing a hydroelectric plant for Coppermine were examined were examined using 1:250 000 scale topographic maps. The sites were:

- Kendall river near Dismal Lakes;
- Escape rapids, Coppermine river;
- Bloody Falls, Coppermine river;

The first two sites were ruled out because of considerations of the magnitude of the load, the length of the transmission lie which would be required and the available head. In addition, the Kendall river froze to the bottom during the winter.

The Bloody Falls site was examined with the objective of providing enough energy to satisfy both the normal electric load and the heating load. Presently, heating is obtained by the direct combustion of home heating oil and diesel generators provide electricity to the community. Development of this site, with this objective in mind, required the construction of an overflow, rockfill dam just upstream of the falls, a diversion/power tunnel and powerhouse.

It appeared that the development of the site, using the available data, was feasible and hence field investigations were carried out at the site in the second phase of the study. These investigations are described in Section 4.3. They allowed the measurement of the available head and a better evaluation of both the river flows and the geotechnicial aspects of the site. Based on the survey data, new maps, using existing photographs, were prepared at a scale of 1:2 500.

The design of the project was left bascially the same, but allowances for the movement of fish in the river were made, since this is an important aspect of this project. The study in the second phase showed that cost of the diversion tunnel, which eventually became the power tunnel, was substantial. Also, there were concerns about guaranteeing the movement of the fish - principally artic char; these doubts arose out of insufficient information of the fish life.

The cost effectiveness of four schemes varying from 5,2 MW to 9,6 MW with investment costs varying from $35 million to $52,2 million, respectively, showed that perhaps the smallest scheme could be viable if the discount rate was taken as 6% p.a. The evaluation also showed that to satisfy the heating load the cost of electricity had to be very small. This was because heating by the direct combustion of heating oil was efficient.

The inefficiency of attempting to harness a site on a large river having a substantial power potential to serve a small and highly variable load was clearly demonstrated. At this point, it was decided to re-examine the site to supply only the normal electric load and to assume that excess energy could be regarded as being utilised for heating. It was also decided to develop the scheme without a dam across the river and so obviate environmental problems concerning the movement of fish in the river.

7.2 DESIGN

7.2.1 Head and Flow

Field measurements indicated that the gross head at Bloody Falls was 6,33 m when the flow was about 700 m^3/s. As the provisional rating curves, Figure A-4.3, show this head decreases as the flow decreases. At the minimum flow of 58 m^3/s the gross head is estimated to be about 5,5 m.

Since the objective of constructing the hydro plant was to replace fuel - diesel and heating oil - then the energy output from the plant should, as far as possible, be firm. Using the predicted flows, Figure A-5.9 and A-5.10, the turbine flows which were examined were 24 m^3/s, 46 m^3/s, 56 m^3/s and 70 m^3/s - i.e., four schemes were examined.

7.2.2. Layout

Since no dam is to be used for the development of the site, it is proposed that a diversion trough be excavated in the river bed from the normal river channel, near the right bank of the river, to the intake situated on the left bank. From the intake a tunnel takes the diverted river flow to the powerhouse and eventually back to the river below the falls, Figure A-7.1

The diversion trough slopes towards the intake becoming deeper as it approaches the intake. The trough is shaped so that the upstream slope is flatter than the downstream one thus inducing flow into the channel without "jumping" the trough. The exact shape of this trough can only be obtained by a hydraulic model. The model will also indicate the behaviour of sediments in the river, as it affects the trough, and how the sediment control works should be designed. The foregoing implies that data on sediment load is available or that collection of it should begin. During spring break up the sediment load is large, but most of it will pass down the falls. At other times, most of the sediment will be deposited in the widenend area of the river upstream of the intake, as is presently occuring.

Except for the largest turbine flow which was investigated, namely 70 m^3/s, there will always be some flow passing down the falls. Details of the intake are shown in Figure A-7.3

In the first two phases of the Study, the powerhouse was located at the end of the tunnel. However, the operating requirement of the turbine requires a very large upstream surge chamber because the available head is small and flows large. To satisfy this requirement it was decided to move the powerhouse to a point just downstream of the two perched lakes, Photo 2. The two lakes would be joined together by excavating a canal which is more than 2,5 m deep to prevent freezing to the bottom Figure A-7.1. The lakes act as a headpond and they are connected to the tunnel by a shaft of the same diameter as that of the tunnel, as shown in the developed profile of the project, Figure A-7.2.

The powerhouse is a deep structure and only a small portion of it is above ground. From an aesthetic point of view it is preferable to the powerhouse which located at the end of the tunnel, and which was entirely visible. The tailrace tunnel, which has been designed to carry stop logs at the exit, is under pressure and thus requires a downstream surge shaft. This shaft is placed about 20 m downstream of the powerhouse. Details of the powerhouse layout are given in Figure A-7.4. for each of the four schemes which were examined.

7.2.3 Hydraulics

The hydraulic calculations were oriented towards obtaining a minimum net head of 5 m. Friction losses in the tunnel formed the major component of the total head loss, and Figure A-7.5 shows the relationship between the required tunnel diameter and flow to achieve a net head of 5 m. The graph summarises these calculations for various surface conditions, but the graph for the lined condition was adoped for the design. The head losses for the four schemes which were examined varied from 0,64 m to 0,73 m.

Hydraulic calculations were also made to determine the diameter of the downstream surge shaft and the variation of the water level in it during load acceptance and load rejection.

7.2.4 Geotechnical

The blocky nature of the exposed rock at the site together with the unknown competence of the metamorphosed siltstone made it necessary to assume, conservatively, that the rock through which the tunnel will be driven will be highly jointed in places. Rock bolts in the roof and a thin shotcrete lining may suffice for structural support. These factors have been taken into account in preparing the cost estimates.

However permeability is also important. It is presently assumed that the rock is frozen and that concrete lining may not be required. However, after the plant is in operation a new permafrost equilibrium line will be established in the area and a seepage barrier may not be maintained. For this reason a concrete lining has been assumed to be required, for the purposes of prefeasibility cost estimates.

In addition to the above, the relatively low topographic profile of the site and the standard requirement of minimum cover above the soffit of the tunnel required the following:

- repositioning of the powerhouse to the site shown in Figure A - 7.2 where the cover is especially small;
- lowering of the powerhouse to obtain the required cover and to keep well below the hydraulic grade line.

7.2.5 Mechanical

In order to reduce costs to a minimum, it was assumed that the existing diesel generators would be maintained and kept as reserve. Consequently, only one turbine and generator was allowed for in the powerhouse. The possibility of using two smaller hydro units was investigated, with resulting reduction in the diesel reserve. However, it was found that the cost of this option, including the reduction caused by savings in diesel reserve, was greater than the cost of the single unit option. For the required flow and range of head conditions which would occur, the only suitable turbine was the Kaplan. The range of the head conditions are dictated not only the range of river flows, as shown in the rating curves, Figure A - 4.3, but also the variation of the load.

The size of the tunnel is quite large and, again, to reduce costs there is no valve in the penstock immediately upstream of the turbine. To isolate the turbine, the intake gate must be lowered and the tunnel and lakes (headpond) drained. Since the lakes are relatively small this does not pose a problem. Finally, the draft tube gate must be lowered and the remaining water in the powerhouse pumped out; this is because of the low elevation of the powerhouse. Similarly, to inspect the tailrace tunnel, the intake gate and stop logs at the exit of the tailrace tunnel must be put in place and the entire water conveyance system pumped out. Since the diesel units act as back up, time is not critical, in terms of reliability, in emptying the system.

7.2.6 Electrical

The synchronous generator, operating at 0,85 lagging power factor, is directly coupled to the turbine which rotates at speeds varying from 105.9 r.p.m., for the largest scheme, to 180 r.p.m. for the smallest scheme. The configuration between the generator and the 12 kV transmission line could be:

- direct coupling of the generator to the transmission line, in which case the voltage at the generator terminal would be 12 kV, or
- placing a step-up transformer between the generator and the transmission line.

It was assumed that the latter standard configuration applied and that the voltage at the generator terminals was 4,16 kV. During a feasibility study of the project the first alternative could be examined. Similarly, standard switchgear equipment and a step-down transformer at the end of the transmission line were assumed.

The operation of the hydro plant could be either remote controlled or automatic. Telecommunication between the existing diesel station and Bloody Falls would be provided by telephone cable attached to the powerline poles. The telephone cable would also serve to operate the intake gate in the event of a malfunction of the plant.

7.2.7 Plant characteristics

Based on the foregoing discussions, the characteristics of the four schemes which were examined are as follows:

Item	Unit	Schemes			
		1	2	3	4
Head					
- gross	m	5,5	5,7	5,65	5,7
- net	m	4,78	5,06	4,98	4,97
Flow	m^3/s	24,0	46,0	56,0	70,0
Diversion trough					
- bottom width	m	4,0	6,0	7,0	8,0
- invert at left bank	m	1,50	0,90	0,70	0,40
Intake structure					
- top elevation	m	20,0	20,0	20,	20,0
- gate sill elevation	m	-3,0	-4,50	-5,00	-6,00
- width of intake	m	11,00	12,50	13,00	13,50
- trashrack					
- number	-	2	2	2	2
- width (each)	m	3,00	3,75	4,00	4,25
- height	m	5,70	7,00	7,50	8,00
- gates		Data as for trashrack			
Tunnel					
- headrace	m	514	514	514	514
- tailrace	m	200	200	200	200
- diameter	m	3,85	5,40	5,79	6,60
Powerhouse					
- number of units	-	1	1	1	1
- turbine type		KAPLAN			
- rotational speed	r.p.m.	180,0	128,6	120,0	105,9
- output	kW	922	1888	2243	2800
Surge shaft					
- length	m	11,0	11,0	11,0	11,0
- diameter	m	4,5	7,0	7,6	8,5
- upsurge	m	4,68	4,97	5,19	5,19
Canal					
- length	m	25	25	25	25
- depth	m	5	5	5	5

7.3 POWER AND ENERGY

Except for the largest schemes, the plant flow is less the minimum flow in the river; the firm energy production is therefore equal to the average energy for these schemes. For the largest scheme, the average flow in the river in March/April is less than the rated flow of the turbine.

The rated output at the generator terminal was determined by using the formula:

$$P = 8\ Q\ H_n \qquad (kW)$$

where,

Q = flow in m^3/s
H_n = net head in m.

In the above formula, the combined efficiency of the turbine and generator was assumed to be 82%.

The rated output and energy from the plant, based on the electrical characteristic of the transmission line, are as follows:

Scheme	Power-kW		Energy - MWh - p.a.			
	Rated	Actual	Rated firm	Actual average	Rated firm	Actual average
1	922	898	7673	7673	7482	7482
2	1888	1788	15712	15712	14911	14911
3	2243	2101	18666	18666	17536	17536
4	2800	2578	22715	23000	21032	21279

7.4 CONSTRUCTION PHILOSOPHY

Construction of the project has been envisaged to take place over a period of thirty four months, but it is possible to shorten this period by about four months. The critical item is the supply and erection of the turbine and generator. Figure A - 7.6 shows the proposed construction schedule, which has taken into account both the available daylight hours, figure A - 2.2, the average temperatures at the site, Section 2.1, and the occurence of the low flow period. This has resulted selecting in a starting month of March.

The diversion trough has been scheduled for construction over two years during the low flow period in March/April. At this time, the ice cover should provide a platform for drilling the holes prior to blasting; the holes will be lined or sleeved so that the explosive charge can be inserted into them. Figure A-7.7 shows the upstream cofferdam in place and covering a portion of the diversion trough. This covered portion will be excavated as the cofferdam which serves as a working platform is progressively dismantled. The use of a rockfill upstream cofferdam was ruled out since the toe would extend too far into the river, Figure A - 7.7. However, the downstream cofferdam is of the rockfill type but has an additional rock protection which would be needed during ice break-up.

The sequence of construction could be as follows:

- construct access road;
- construct site facilities;
- construct upstream and downstream cofferdams;
- start excavation of diversion trough and tunnel;
- start excavation of powerhouse;
- start excavation of intake;
- complete diversion trough;
- dewater small lake and connect to tunnel;
- complete tunnel and surge shaft;
- complete powerhouse;
- excavate tailrace;
- link two lakes with canal;
- install equipment and erect transmission line;
- remove cofferdams;
- commission plant.

SECTION 8 COST ESTIMATES

8.1 GENERAL CONSIDERATIONS

Cost estimates were prepared for four schemes by applying unit costs, to specific quantities. These costs were compiled with the aim of reflecting construction conditions in the Northwest Territories. Some of the quantities have been based on the available topographic maps, and there is, therefore, an inherent error. The costs which have been supplied must be considered as order of magnitude values with an error of about ± 20%.

The following guidelines were used in preparing the costs:

- basic unit costs were adjusted to reflect the local conditions;
- the accesses were properly constructed roads;
- a three year construction period was assumed for each scheme to calculate the interest during construction at an 8% real discount rate.

Costs resulting from any environmental mitigation requirements are considered to be covered by the contingency allowances.

8.2 COST ESTIMATES

The investment costs for the various schemes are given in Tables A - 8.1 and A - 8.4, below.

These Tables clearly show that about 70% of civil works cost are taken up by the tunnel and the powerhouse. Also, the cost of the turbine and generator form about 50% of the cost of the generating equipment.

The Tables indicate a decreasing cost/kW as the plant size increases; and, as will be seen in Section 9 the cost of producing the energy also decreases as the plant size increases. This is because the generatable energy increases with increasing capacity.

The estimated peak labour for the selected scheme is about 165 of which about one third would be recruited locally. Also the estimated disbursements in the community is about $1,5 million.

TABLE A - 8.1

COPPERMINE DEVELOPMENT

COST ESTIMATES (1984 dollars)

Alternative 1
922 kW

Item	Costs - $ x 10^6	
Civil Works		
Access	0,605	
Cofferdams	0,337	
Intercepting trough	0,170	
Intake	0,489	
Tunnel and surge shaft	2,652	
Canal	0,053	
Powerhouse	1,282	
Tailrace	0,047	
Sub-total		5,635
Electrical and Mechanical		
Turbine	0,572	
Generator	0,288	
Miscellaneous equipment		
Electrical	0,213	
Mechanical	0,259	
Intake Equipment	0,291	
Outlet equipment	0,070	
Transmission line	0,860	
Sub-total		2,553
Indirect construction costs (15% of civil works)		0,845
Engineering and management (10%)		0,903
Sub-total		9,936
Contingencies (10%)		0,994
Construction cost		10,930
Interest during construction (8%)		1,182
Capital cost		12,112
Cost/kW	$13 136	

Notes: 1) Estimated capital costs are ± 20% accuracy
2) Does not include costs for feasibility and environmental studies

TABLE A - 8.2

COPPERMINE DEVELOPMENT

COST ESTIMATES (1984 dollars)

Alternative 2
1888 kW

Item	Costs - $ x 10^6	
Civil Works		
Access	0,605	
Cofferdams	0,390	
Intercepting trough	0,270	
Intake	0,806	
Tunnel and surge shaft	4,038	
Canal	0,053	
Powerhouse	2,219	
Tailrace	0,086	
Sub-total		8,467
Electrical and Mechanical		
Turbine	0,900	
Generator	0,515	
Miscellaneous equipment		
Electrical	0,333	
Mechanical	0,361	
Intake Equipment	0,406	
Outlet equipment	0,180	
Transmission line	0,860	
Sub-total		3,555
Indirect construction costs (15% of civil works)		1,270
Engineering and management (10%)		1,329
Sub-total		14,621
Contingencies (10%)		1,462
Construction cost		16,083
Interest during construction (8%)		1,804
Capital cost		17,887
Cost/kW	$9 474	

Notes: 1) Estimated capital costs are ± 20% accuracy
2) Does not include costs for feasibility and environmental studies

TABLE A - 8.3

COPPERMINE DEVELOPMENT

COST ESTIMATES (1984 dollars)

Alternative 3
2243 kW

Item	Costs - $ x 10^6	
Civil Works		
Access	0,605	
Cofferdams	0,426	
Intercepting trough	0,319	
Intake	0,881	
Tunnel and surge shaft	4,228	
Canal	0,053	
Powerhouse	2,570	
Tailrace	0,094	
Sub-total		9,176
Electrical and Mechanical		
Turbine	1,047	
Generator	0,605	
Miscellaneous equipment		
Electrical	0,379	
Mechanical	0,403	
Intake Equipment	0,570	
Outlet equipment	0,226	
Transmission line	0,860	
Sub-total		4,090
Indirect construction costs (15% of civil works)		1,376
Engineering and management (10%)		1,464
Sub-total		16,106
Contingencies (10%)		1,611
Construction cost		17,717
Interest during construction (8%)		1,831
Capital cost		19,548
Cost/kW	$8 715	

Notes: 1) Estimated capital costs are ± 20% accuracy
2) Does not include costs for feasibility and environmental studies

TABLE A - 8.4
COPPERMINE DEVELOPMENT
COST ESTIMATES (1984 dollars)
Alternative 4
2800 kW

Item	Costs - $ x 10^6	
Civil Works		
Access	0,605	
Cofferdams	0,457	
Intercepting trough	0,377	
Intake	0,964	
Tunnel and surge shaft	4,717	
Canal	1,053	
Powerhouse	3,384	
Tailrace	0,146	
Sub-total		10,703
Electrical and Mechanical		
Turbine	1,205	
Generator	0,740	
Miscellaneous equipment		
Electrical	0,443	
Mechanical	0,453	
Intake Equipment	0,570	
Outlet equipment	0,310	
Transmission line	0,860	
Sub-total		4,581
Indirect construction costs (15% of civil works)		1,605
Engineering and management (10%)		1,689
Sub-total		18,578
Contingencies (10%)		1,858
Construction cost		20,436
Interest during construction (8%)		2,232
Capital cost		22,668
Cost/kW	$8 095	

Notes: 1) Estimated capital costs are + 20% accuracy
2) Does not include costs for feasibility and environmental

SECTION 9 - ENVIRONMENTAL

9.1 PROJECT DESCRIPTION

The proposed Coppermine hydro scheme is located at Bloody Falls which is about 15 km upstream of the community on the Coppermine river. The run of the river scheme has no dam across the river, and consists of an interception trough, intake, tunnel, and powerhouse. There is a transmission line and access road between the falls and the community. The project is capable of providing electrical energy to supply the normal electric load with excess energy being used for heating.

Environmental concerns over the project in Coppermine mainly surround the fishery on the Coppermine river. Species in the river include arctic char, whitefish and trout. Other concerns relate to the aesthetic appearance of the falls and the existing canoe portage.

9.2 FISHERY

The Coppermine river fish populations are virtually undescribed. A recent paper by staff of the Freshwater Fish Institute in Winnipeg (Gillman and Christopherson, 1984) examines age, length and weight of char caught in 1981, but this represents the only known published data. All other information is based on the knowledge of Coppermine residents.

Arctic Char

Relatively little is known about the complete life cycle of the char which inhabit the Coppermine river system and estuary. Local knowledge suggests the following migration cycle:

Char Run	Cohort	Migration Period
Incoming	"Pale Char" (larger)	August - early September
Incoming	"Colour Char" (smaller)	mid to late September
Outgoing	?	October/November
Outgoing	?	June/July

The commercial quota has been set at a mere 223 kg/year. Domestic harvests from the Coppermine river have been reported to have ranged from 6 700 to 67 000 kg/year. These harvests of char are taken mainly between Bloody Falls and Coppermine. The largest catches are obtained with nets in both open water and under the ice. Rod and reel catches are also quite common on the downstream side of the falls. Numerous cabins and tents are erected on the banks of the Coppermine river to accommodate the fishermen and their extended families during the summer.

Char is processed by filleting and air-drying and is used as a "snack". Other portions of the catch are frozen in private or community freezers. Recent harvest statistics suggest 8 530 char for 1983 or 22 860 kg.

Arctic char is primarily an anadromous species (spends part of its life in the ocean but returns to fresh water for spawning), although isolated non-migratory populations occur in lakes. Anadromous populations occur primarily around the Arctic Ocean, but also along the coasts of the northern half of Hudson Bay, Labrador, north-east Newfoundland, western Alaska and all of Greenland and Iceland. This distribution generally corresponds to the distribution of sea-ice in winter (ref. 39).

Generally, in the central Canadian Arctic, char spawn in lakes because the rivers freeze completely in winter (ref. 39). Whether or not this is true of the Coppermine river population is unknown. The usual pattern of migration is as follows:

- mid-August to September - char enter fresh water to spawn
- char overwinter in fresh water
- char descend rivers to salt water during ice break-up
- char spend 1-3 months feeding in coastal waters before returning to fresh water.

Char generally spend the first 3-5 years of life entirely in fresh water before making the first seaward migration. Larger fish generally commence migrations in advance of smaller immature fish. Only a portion of the mature fish returning to fresh water will spawn in a particular year.

Char have been observed to ascend Bloody Falls and proceed further upstream.

Whitefish

The other known migrating species in the Coppermine river are whitefish. As with the char, the migration, spawning and other habits of this fish in the Coppermine river system are relatively unknown. The last reported catch was 5 188 for 1983 based upon a reporting rate of 50%.

Virtually nothing specific is known about the populations of other fish species which use the Coppermine river; these include broad whitefish, round whitefish, lake trout and probably arctic grayling. However, it is probable that all of these species overwinter in deeper lakes and river reaches, which may require them to migrate to upstream of Bloody Falls. All of these species spawn in fresh water although some species, e.g., whitefish, may feed in coastal waters during parts of the year.

In summary, the obvious concern with respect to fisheries is the continued passage of migrating fish through Bloody Falls into the upper reaches of the Coppermine watershed and to allow for their return to the estuary.

9.3 WILDLIFE

Seals and caribou appear to be the most important wildlife species which form a part of the diet of the Inuit at Coppermine, but other animals, including polar bear, musk-ox, small game and possibly other marine mammals, are also used. It appears that these populations would be unaffected by the project, but this should be confirmed by further discussion with local wildlife hunters if the project proceeds beyond the present stage.

9.4 AESTHETICS

Bloody Falls is an impressive site from an aesthetic point of view. The narrowed river within a rock canyon with a drop of about 6 metres over 1 000 metres allows the formation of a series of standing waves from the top to the foot of the falls. These standing waves, some of which can attain a height of about 2,5 m, and the swift currents and eddies present an awesome display of water power.

The falls are enjoyed by local residents of Coppermine, fishermen, tourists and canoe trippers. There would be a concern from all these groups of people should the aesthetics be significantly affected by any proposed power project.

9.5 CANOE PORTAGE

The existing trail along the west bank of the falls provides a means for canoe trippers to portage around the falls. Therefore any changes to this trail would have to be mitigated through the provision of an alternative portage alignment. The steepness of the present trail in some areas perhaps offers an opportunity for a better route.

9.6 ENVIRONMENTAL IMPACTS AND MITIGATIVE MEASURES

The maintenance of the population of arctic char and likely several other species in the Coppermine river depends on unobstructed passage upstream and downstream through Bloody Falls. Prevention of this passage would seriously jeopardize these populations and cause severe hardships for the community. However, the present design of the project does not interfere with movement of fish in the river. There is need, however, to ensure that the fish does not enter the intake or swim up the tailrace tunnel. This can be achieved by the use of screens which is normal practice in hydro project development.

The rated turbine flows are less than the anticipated minimum flow in the river during March/April, for all but one scheme, but there will be a substantial flow depletion from the normal river channel. It is therefore important to confirm that during these months fish do not move in the river. The time of construction of the interception trough and the operation of the power plant assumes that there is no movement of fish up or down the river during the low flow period.

To provide baseline information on the fish population for use in designing the project, a detailed field program is required. The basis of the program would be counting fences operated in two consecutive years. Fish ascending and descending the rapids would be enumerated by species and size and tagged and samples would be taken for more detailed analysis (age, length, weight, sexual development.

Based on a field program lasting two years, making considerable use of local assistance, the costs of the required fisheries studies, including laboratory work and reporting, are likely to be in the order of $300 000.

As far as access around the falls is concerned, the construction of a road from the bottom of the falls to the intake will be of benefit to canoe trippers.

Aesthetics

The hydro scheme is designed as a run-of-the river development which will include the construction of a diversion water conveyance system. Due to the flow characteristics of the river and the pattern of the forecasted load, over 90% of the flow during the summer will be spilled, thereby not visibly altering the downstream aesthetics of the present rapids. During the winter the flow in the rapids will be reduced to about 20% the normal discharge.

The top of the powerhouse which is located downstream of the perched lakes - just to the right of lakes in photo 2 - will be not much above the existing ground level. The completed powerhouse thus presents a minimum of interference with the surroundings.

SECTION 10 - APPLICATION OF WIND TURBINE GENERATORS

The use of wind energy as a means of reducing the oil consumption of diesel generating plant in remote locations has been frequently proposed. The simplest form of wind turbine generator is the vertical axis Darrieus rotor coupled through a speed increasing gear box to an induction machine. The Darrieus turbine, having fixed blades, cannot self-start under all conditions so that the induction machine is used for starting as a motor and automatically transfers to generating operation when it crosses synchronous speed.

The induction machine draws its excitation from the system to which it is connected. Hence, it follows that the wind turbine generator most always operate in parallel with another generating source.

Another consideration is that the wind turbine "fuel" source, viz. the wind, is continually varying so that firm power in the normal sense cannot be guaranteed. However, based on statistical wind data, it is possible to estimate the energy output of a wind turbine generator per year. The average power output of a wind turbine generator is of the order of 20 to 30 percent of its continuous power rating.

The wind turbine capacity in terms of continuous power rating relative to the minimum load demand of the connected system in an important factor which determines the stability of operation and the economic value of the wind turbine installation. For example, if the wind turbine installed capacity exceeds the system load demand then it will runaway unless it is shut down before the situation arises. In a multi-unit installation, one or more units may be shut down to preserve system stability. This clearly adversely affects the economics since wind turbines will have been shut down when they are most productive. The alternative to shutting down the wind turbines is to provide an artificial load such as a water heating system, space heating or equivalent.

The question of the maximum acceptable capacity of wind turbine installation is very site specific and must properly be addressed on an hour-by-hour operation basis, with full knowledge of the hour-by-hour load pattern and wind pattern. A computer program capable of such analysis does exist.

For present purposes, it is assumed that the wind turbine installation capacity does not exceed the minimum system load demand so that all the energy derived from the wind can be usefully absorbed by the load system.

Wind data

From "Canadian Climate Normals, Volume 5, Wind" published by Environment Canada, the annual average wind speed (AAWS) for Coppermine is 16,6 km/hr or 10,31 m.p.h. at 10,7 m above ground level. Based on a typical shear index of 0,17, this is equivalent to 10,2 m.p.h. at 10 m.

The data indicate that the monthly mean wind speeds are below average from March to July which suggests that the availability of wind energy does not ideally match expected variations in the load characteristics. From August to February the wind speeds are above average, but not by much, and the generated energy can conceivably be used to meet a heating load.

It should be noted that data from the above source is only indicative and better sites may be available dependent on the local topography.

Energy production

All estimates presented below are based on the DAF-Indal 500 kW vertical axis Darrieus wind turbine generator. The curve of net annual energy produced as a function of the site annual average wind speed measured at 10 m above ground level is shown in the following table, and it can be seen that it is necessary to extrapolate the curve to include Coppermine.

AAWS at 10 m, m/s mph	5.26 11.77	6.13 13.71	7.01 15.68	7.88 17.63	8.76 19.60	9.64 21.56
Annual energy, MWh (net)	477	752	1039	1305	1524	1685

It is estimated that the wind turbine would produce 260 MWhe per annum.

All the data presented assumes a 95 percent availability for the wind turbine. It should be noted that for this particular wind turbine the cut-in wind speed (minimum wind speed for operation) is 5.6 m/s (12.5 mph) at 10 m height. Since the annual average wind speed is only 10.2 mph at 10 m height, it follows that the machine would be operational for only a small percentage of the time. This effect is reflected by the very low energy production. If the cut-in wind speed could be reduced eg., by de-rating the unit or by using a variable-speed power tain some improvement in energy production could be achieved.

Because of the increase in air density, the power output of a wind turbine increases as the temperature decreases. No allowance has been made for this.

Wind Turbine Costs

The costs given below are for a one-off, special order machine in 1984 dollars:

Cost of basic materials	-	625,000
Additional design features for arctic environment (15% of basic cost)	-	93,750
Additional transportation costs to NWT (50 tons x 500)	-	25,000
		$ 743,750
Basic installation cost	-	250,000
Adjustment for NWT (relative to Edmonton - 6%, and Coppermine - 16 x 3% = 54% total)	-	135,000
Total installation cost	-	$ 385,000
Total installed cost	-	$ 1,128,750

Although a cost of $2 278/kW is indicated by the above cost, the value of the wind machine must be examined in terms of the cost of energy. This is because the unavailability of wind at all time.

Cost of Energy

For wind turbine generators, the cost of energy (COE) is normally calculated from the following formula:

$$\text{COE} = \frac{(\text{Cost} \times \text{FCR} + \text{O\&M} \times \text{LF}) \times 100}{\text{AE}} \quad ¢/\text{kWh}$$

Where Cost = total installed cost of the wind turbine generator
FCR = fixed charge rate (Cost x FCR = annual repayments over a 30 year plant life)
O&M = operating and maintenance cost (taken as 2% of the capital cost)
LF = levelizing factor (taken as 2 for a 30 years plant life)
AE = annual energy produced per year in kWh.

For Coppermine, using the previously derived data, and for FCRs of 6, 8 and 10 percent, the cost of energy calculated from the above formula is:

$$\text{Cost of energy} = \left[\begin{array}{l} 34.73\ ¢/\text{kWh for FCR} = 6\% \\ 43.41\ ¢/\text{kWh for FCR} = 8\% \\ 52.10\ ¢/\text{kWh for FCR} = 10\% \end{array}\right.$$

After the collection of site specific data extending over at least one year, it is possible to construct a wind turbine of the type mentioned also in one year. To meet a higher load, a number of machines must be erected. It must be concluded, however, that the available wind data indicate the Coppermine is not particularly favourable for wind turbine generator application.

SECTION 11 - PROJECT EVALUATION

11.1 GENERAL

The evaluation of the Coppermine hydro project comprises two elements.

- Optimization of the project size and installations, as well as the on power date, for a range of interest rates.
- Derivation of net benefits for a range of discount rates, based on the capacity and energy capability of the selected project. This defines the projected internal rates of return (or equalizing discount rate) for the project, and hence the interest rates at which it will be economically viable. Also sensitivity tests to measure the potential impact of capital cost, fuel price changes and load growth rates on the project's viability.

The development of a methodology for the above analyses recognized a number of factors, as follows.

- The alternative approaches are to carry out a unit cost comparison, between energy costs from Coppermine hydro and from alternative thermal (diesel) generation, or to derive results based on a limited scope system study.
- The project is sized, approximately to meet electrical loads, based on firm energy capability. Therefore significant amount of surplus energy will be available during most of the year and the energy may be used to replace some of the existing heating oil requirements.
- project benefits will result from displacement of existing diesel generation, deferment of future diesel installation, and reduction in future heating oil costs.
- The actual diesel generation that would be replaced by the Coppermine project will change over the years as existing units are retired, and the relative proportion of electrical and heat consumption varies.

A further consideration is that comparisons between hydro and diesel should take into account reliability of supply i.e., ensure that these alternatives (as measured by projected costs) will provide the same quality of service.

11.2 OVERALL APPROACH

The evaluation of the project measures primarily benefits due to replacement of diesel generation. However, as shown by the results, the potential benefits that would result from use of surplus hydro energy (above the requirements to meet the electrical load) for heating would have a significant impact on the viability of the hydro project.

In order to take into account the change in the value of the Coppermine hydro generation over time the analysis has been based on comparisons of total system operating costs. This was used to provide results for final project optimization and project evaluation, including sensitivity tests. Benefits from the use of electricity for heating have been applied as a credit (after allowing for house conversion costs), based on the present worth of year by year benefits.

Comparisons made on a system basis are designed to evaluate a single project, however they are based on total system capital and operating costs. The general approach is that a preferred system new generation plan, excluding the (hydro) project being evaluated, is developed as the reference case. Then the hydro project is inserted in the plan and corresponding adjustments are made by deferring or resizing alternative or later projects.

For each plan total discounted capital and operating charges are obtained for a series of interest rates. The evaluation period covers the total service life of the hydro project, to allow for changes in generation costs associated with replacing existing thermal (or in the case) diesel alternatives.

The system analysis used is typical of available models and includes the following features.

- Scheduling of new plant to ensure equal reliability for each plan;
- a total evaluation period of about 40 years after the hydro plant on power date. The use of this procedure assigns a time value to money, and therefore permits the different total capital and cash flow requirements of each alternative to be compared on a common basis;
- annual fuel costs are calculated for the stacking of individual plants, based on the number of hours of operation and the total energy generation assigned to each plant. Separate heat rates can be applied for each existing and new thermal unit;

- the hydro plant is stacked preferentially using firm capacity and average energy. The balance of the load requirements are met by diesel units which are ordered according to their variable fuel and operating costs;
- operation, maintenance, administration, interim replacement and insurance charges are included;
- transmission additions, not common to both alternatives, are included;
- the existing and new plant is replaced at its retirement date.

This type of analysis provides the advantage of measuring benefits from replacing high cost generation by new hydro and the change in generation with time.

The primary results used in this assessment are:

- net benefits as a function of installation size, discount rate, fuel cost and load growth;
- the internal rates of return and benefit costs ratios for the various hydro schemes being tested.

In this case a reference generation plan was prepared for the period 1984 to 2029, based on continued use of diesel units to meet the electrical load. This assumed the medium combined load forecast.

The alternative test plan with the Coppermine hydro project assumes that the hydro project will be commissioned during the period 1990-93 (alternative on-power dates were tested). Later diesel additions and retirements depended on the scenario being tested, as described later.

The electrical system load shows a significant seasonal variation, with summer peak capacity and energy demands being about 60% of the maximum winter values.

The additional heating load, converted to equivalent electrical units shows a similar variation. When the two loads are combined, the summer demands are about 30% of the winter requirements.

The heating load, some of which could be met from surplus hydro generation is large, relative to the electrical load. In 1990 the comparable annual values, for the base or medium load forecast, are

	Peak kW	Annual Energy - kWh
Electrical load	784	3,464
Heating load	4 169	14,347
Total load	4 953	17,811

By comparison the selected hydro scheme would have the following generation capability (before allowing for transmission losses)

Rated capacity	1 888 kW
Firm/Average Energy	15,7 GWh
Available Capacity Factor	95%

As noted earlier the plant installation corresponds to the firm river flow. Consequently, the available energy generation is limited by the installation, not available river flow and thus firm and average energy are the same.

Comparison of the demands and available hydro generation show the extent to which surplus hydro energy would be used for heat.

(As is described later the optimization studies considered a wide range of installations, the lowest of which (922 kW) corresponds to the median electrical peak demand in 1995.)

The net benefits for the hydro project were defined in terms of the present worth of system capital and operating costs as

Benefits = Reference (all diesel) plan cost
less - costs for the alternative plan with the hydro project
plus net benefits from displacing oil heating.

For these analyses load growth and new plant scheduling was provided up to December 2029. All costs were present worthed to January 1984, and all costs were expressed at 1984 price levels.

The procedures for expressing benefits and costs are outlined below.

11.2.1 Measurements of Benefits and Costs

All project benefits and costs accruing to the project proponent are considered. However, some costs such as transfer payments (in particular taxes) are excluded.

Definition of Costs

The cost streams are composed of capital costs, fuel costs, insurance costs, operating and maintenance costs, replacement costs, and the cost for additional environmental/feasibility studies. Costs which have already been spent or are already irrevocably committed (sunk costs) are ignored in the appraisal.

Definition of Net Benefits due to the Project

The project benefits are based upon the avoided costs (capacity and energy costs) resulting from the project implementation.

As the project is part of an integrated system, the benefits are estimated by comparing total system costs with and without the project, with the benefits being equal to the difference between the total costs of the two cases without assigning any cost to the project. The difference in total costs, after including the discounted costs of the project, and after adjusting for the heating credit, will be the net present value of the project.

The heating credit is obtained as the present worth of electrical heat supply benefits (i.e., 90% of the avoided oil costs) less the corresponding costs of heating unit conversions.

Internal Rate of Return

The basic criterion suggested to measure the economic viability of the project is the internal rate of return (IRR). This is the discount rate at which the discounted stream of benefits is equal to the discounted stream of costs. This criterion is convenient as the derived breakeven rate of return may be compared directly to a 'decision' discount rate.

The NCPC has proposed that the analyses, which are based on constant prices, be based on a range of discount rates from 6 to 10%, and that optimization decisions be based on a decision rate of 8%.

Benefit Cost Comparisons

For a single project considered as part of a system plan the benefit cost ratio for the given project can be represented by the benefit cost ratio as follows:

$$\text{Benefits/Costs} = \frac{\text{Net Benefit due to the Project} + \text{PW of project costs}}{\text{PW of project costs}}$$

The result of the various optimization studies have been shown in term of benefit/cost ratios.

11.2.2 Optimization Studies

The objectives of the optimization studies were to define the project physical characteristics which will yield the maximum net benefits, and for the selected scheme, to determine the preferred on-power date.

The optimal plant installation is such that the last increment of costs is equal to the increment in the benefits. The optimum is reached when the marginal costs are equal to the marginal benefits, i.e., when the marginal B/C ratio is equal to one.

The selected optimum size or installation is a function of discount rate. For this study the optimum installation was determined for discount rates of 6, 8 and 10%.

11.3 GENERATION SCHEDULES

The assessment of net benefits and breakeven rates of return was carried out for project optimization and evaluation using present worth comparisons of system costs.

The reference electrical load growth, projected heating load, existing generation and assumed new plant scheduling are described as follows.

11.3.1 System Loads

The development of the load forecast is described in Section 3. The analysis have resulted in two forecasts for the electrical and the combined electrical plus heating load. They are

- base electric load and medium combined load,
- low forecast of each of these loads

These forecast demands are shown in Figures A-9.1 and A-9.2. The optimization studies have been based on the base case forecast, and the low forecast was used in the sensitivity tests applied to the preferred scheme.

Representative forecast generation demands are as follows

REFERENCE CASE FORECAST LOADS

	Base Electrical Load		Medium Combined Electrical and Heating	
	Peak kW	Generation Energy GWh	Peak kW	Generation Energy GWh
1985	679	2,99	4 677	16,77
1990	784	3,46	4 953	17,811
2000	1 000	4,38	5 783	20,841
2010	1 214	5,32	7 048	25,404
2029	1 778	7,79	10 268	37 009

The peak loads and energy given in the above table represents what is required at the point of generation.

LOW FORECAST LOADS

	Low Electrical Load		Low Combined Electrical and Heating	
	Peak kW	Generation Energy GWh	Peak kW	Generation Energy GWh
1985	666	2,93	4 630	16,56
1990	694	3,04	4 820	17,23
2000	796	3,51	5 560	19,87
2010	969	4,28	6 773	24,23
2029	1 413	6,24	9 871	35,30

The analysis is carried out using 13 intervals per year, and requires a system load duration curve.

The distribution of peak system loads by interval over a year, and the interval (4 weeks) load duration curve was obtained from the NCPC.

For the analyses the interval peak demands are prorated using the forecast peak load for the year. Similarly the actual load duration curve in any year is obtained by adjusting the reference load duration shape to correspond to the desired peak demand and energy values for the period.

11.3.2 Existing Generation

Information on existing generation plant in Coppermine was obtained from the NCPC, as follows:

Engine Make and Model	Capacity kW	Year Installed
Mirrlees EV6	200	1967
Mirrlees EV6	200	1967
Mirrlees EV6	200	1967
Mirrlees EV6	375	1973
Cat D398	600	1976

Further information from the NCPC on these units included:

- suggested service life of 20 years,
- 1983 O & M Costs (including administration and general expenses) for 1983/84 of $859 786,
- 1983/84 actual generation of 2,655 GWh and peak load of 620 kW,
- schedule maintenance for each machine of 18 days per year,
- a list of forced outages for the years 1982 to 1984.

The above information was used in establishing the generation plans, with and without the hydro project, and to defined operating costs and reliability requirements.

11.3.3 Reference Case New Plant 1984-2029

The reference generation plan is the expected schedule of new plant required to meet the electrical load only, for the period up to 2029.

This plan is based on the following criteria:

- medium combined load forecast,
- diesel plant life of 20 years
- scheduling to meet a LOLE criteria, based on past performance,
- new diesel units of 600 kW.

LOLE Analysis

The LOLE (loss of load expectancy) criteria was set at 15 hours per year. A reliability analysis carried out over the period 1980/81 to 1983/84 showed that LOLE values varied from 12 to 18 hours and a value of 15 hours per year was selected as representative of part performance (Figure A-9.3). This analysis assumed a forced outage rate of 10% for the diesel unit together with an 18 day maintenance period for each diesel unit. Historical NCPC data on forced outages was not used as it was incomplete.

LOLE analyses with hydro assumed a forced outage rate rate of 3% for the hydro plant.

The LOLE analysis used measures on a probabilistic basis the aggregate times that the peak load will not be met and also the amount of the unserviced load expressed in terms of energy deficiencies. It should be noted that the time for which the demand exceeds the supply usually implies only minor deficiencies that can result in voltage drops rather than system outages.

The analysis takes into account system load shapes, plant stacking, a maintenance schedule and probable forced outage rates.It is based on 13 four-week periods in a year.

The procedure uses the net thermal load duration curves to calculate the risk associated with having insufficient generation to meet the load. The risk is calculated as a Loss of Load Expectancy (LOLE) in hours per year.

The LOLE analysis for this study was done using interval load duration curves, with maintenance of thermal units scheduled automatically.

To take account of unit maintenance the planned outage rate was added to the forced outage rate, thus the planned outage rate is treated as a random variable.

Plant Additions and Retirements - All Diesel Plan (Medium Combined Load)

Year	Retirement kW	Additions kW	Installed Capacity kW
1984			1 675
1987	3 x 225	2 x 600	2 2 00
1992		1 x 600	2 800
1993	1 x 400		2 400
1996	1 x 600	1 x 600	2 400
1999		1 x 600	3 000
2007	2 x 600	2 x 600	3 000
2012	1 x 600	1 x 600	3 000
2016	1 x 600	1 x 600	3 000
2019	1 x 600	1 x 600	3 000
2020		1 x 600	3 600
2027	2 x 600	2 x 600	3 600
	5 875	7 800	
Net Addition		1 925	

The above reference plan is keyed to maintaining a LOLE of less than 15 hours per year. Representative projected installations, loads and reserve margins are,

Year		1990	2000	2020
System Load	- kW	784	1 000	1 486
Installation	- kW	2 200	3 000	3 600
Reserve	- kW	1 416	2 000	2 114
	- %	181	206	142

11.3.4 Plan with Coppermine Hydro - Medium combined load

The alternative plan with the Coppermine hydro project, as selected in the optimization studies described in Section 9.6, follows the same criteria used for the reference plan except that;

- diesel units are not retired after the hydro plant is brought into service. Fixed diesel operating costs are included, however at 50% of the full rate assumed with normal operation.

The revised schedule of plant additions and retirements for the alternative plan with the selected hydro scheme (1 888 kW) is as follows;

Year	Retirement kW	Additions kW	Installed Capacity kW
1984			1 675
1987	3 x 225	2 x 600	2 200
1992		1 888	4 088
	675	3 088	
Net Plant Additions		2 413	

The scheduling of plant up to 1991 is the same as for the reference all diesel plan. Thereafter the hydro project, and availability of diesel units, that would otherwise be retired, provides considerable excess peak and energy capability, in respect of the reliability criterion.

Representative projected installations, loads and reserve margins are,

Year		1990	2000	2020
Electrical System Load	- kW	784	1 000	1 486
Installation	- kW	2 200	4 088	4 088
Reserve	- kW	1 416	3 088	2 602
	- %	181	309	175
Total Electrical and Heating Load	- kW	4 953	5 783	8 588

11.4 GENERATION COSTS

The comparison of generation costs, whether on a unit cost or system plan basis, requires capital and operating charges to be estimated.

Capital related charges include

- interest
- depreciation
- interim replacement
- insurance.

Operating charges include

- operation and maintenance
- general administration of overhead
- fuel.

The operation and maintenance costs for existing diesel units were provided by the NCPC. Corresponding costs for the new hydro and diesel projects were estimated, and interim replacement, insurance and overhead costs were taken from USFERC guidelines.

The capital related charges and operating costs used in the comparisons are described as follows.

11.4.1 Capital Related Charges

Interest Rates

There is a wide range in the real interest or discount rates presently being used by international lending agencies on which a project's viability is based. For comparisons made in constant dollars, i.e., excluding escalation, most agencies in Canada use rates between 3 and 10%. For this study a reference discount rate of 8% has been used for project element optimization and benefit cost ratios have been derived for discount rates of 6, 8 and 10%.

Service Lives and Depreciation

In this economic analysis depreciation allowances were calculated on the basis of sinking fund payments

- to replace the capital cost of the project by the end of its useful service life

- to take into account the time value of money.

The service life assumed for a project is a function of the size and type of generation, ranging from about 20 years for diesel to more than 50 years for major hydro plants. The straight line depreciation method was not used since a financial analysis was not being done.

The project life of hydro plants is theoretically measured by the life of the dam and major civil structures, since electrical and mechanical equipment can be replaced on an interim basis.

It is noted that for accounting purposes all types of generating stations are written off at a shorter life than they may be expected to last for.

For the system cost comparisons the following service lives for new or recent plant have been assumed.

Generation Type	Service Life - Years
Hydro	40
Diesel	20

These service lives were suggested by the NCPC.

Interim Replacement

The depreciation based on the overall service life of the project does not allow for the replacement of major items with shorter service lives than the overall project. An allowance for interim replacement is therefore included in the computation of annual costs to make provision for replacing such short-lived items.

The following annual interim replacement rates were used. These are expressed as percentage of capital cost, (source USFERC).

Hydro	0.22%
Diesel plants	0.35%

It may be noted that interim replacement costs for existing units are not required as such capital related charges are common to both alternative plans. This applies also to insurance allowances.

Insurance

An allowance is included for, or in lieu of, annual insurance costs to cover damages, public liability etc.

Annual amounts, expressed as a percentage of capital costs, were used as follows, (source USFERC).

Hydro	0.10%
Diesel plants	0.25%

11.4.2 Operating Costs

The basis for the operation, maintenance and general administration costs used in the generation cost comparison is outlined as follows.

Operation and Maintenance Costs

Hydroelectric Plants:

Operation and maintenance costs for small hydro can be a significant component of the total annual costs for a project. These costs in practice will vary significantly, not only with project size (expressed on a unit capacity basis) but with plant location, owner policy, staffing/maintenance procedures and to the degree to which operation is remotely controlled or automated. This cost category does not cover periodic major maintenance/replacement requirements which are covered by the interim replacement allowance.

The annual operation and maintenance cost allowance, used for economic comparisons, for hydro is conventionally considered as a fixed amount on an installation basis. Hence annual costs can be expressed in term of $/kW of installation.

As may be expected unit costs ($/kW) are generally significantly higher for small projects as compared with larger developments. This will be particularly true for projects where reliability is important and where very small units are used to meet isolated loads.

The only available statistical data of significance is that which was formerly provided by the USFERC for plants with installations above 2,5 MW. This data has been extrapolated and adjusted to conform with limited available cost data to provide a relationship between unit O & M costs and installation, and this has been used for estimating costs for the Coppermine project.

The operation and maintenance costs used for the various Coppermine hydro scheme alternatives (as tested in the optimization study) are as follows;

Scheme	Installation	O & M $/kW/year
1	922	186,2
2	1 888	106,4
3	2 243	93,1
4	2 800	79,8

The above costs include an allowance of 40% above basic costs to cover incremental administrative and general expenses that will result from the project.

Diesel Units:

Annual operation and maintenance costs for internal combustion units are conventionally expressed in terms of a fixed cost (per kW) and a variable cost (per kWh). Both the fixed and variable costs are a function of unit size with costs decreasing with increase in unit size.

For the existing projects the total operation and maintenance costs have been provided by the NCPC.

For the fiscal 1983/84 year these were stated as $859 786 for the total 1 675 kW, 5 unit diesel installation. These include amounts for administration and general expenses, however also include allowances for interest depreciation and fuel.

The net applicable reported amount is $335 000 which has been increased by 4% to $350 000 to give 1984 and variable expenses on the basis of

- 65% fixed costs,
- 35% variable costs.

These costs exclude any capital related charges and fuel costs.

As noted previously, for the plan with the hydro alternative, diesel units still in service in 1992 were assumed to be retained in service on a standby basis. As their operating time would be minimal a reduced fixed operating cost of $70/kW/year was assumed.

11.4.3 Fuel Costs

The comparison of alternative system plans, with and without the Coppermine hydro project are based on the present worth of all capital and operating costs. In these analysis the annual system fuel costs are calculated from the stacking of individual diesel units based on the number of hours of operation and the total energy generation assigned to each unit. Costs are based on fuel prices and heat rates.

The reference price for distilled diesel fuel is taken as 54 cents/litre. Assuming a heat rate of 9 960 BTU/kWh for existing and future diesel units, and the diesel fuel cost of $ 16,10/MBTU, the derived fuel generation cost is 16,04 cents/kWh. (54 ¢/l x 9 960 BTU/kWh x 1,22 l/kg x 1kg/40 931 BTU = 16,04)

11.4.4 Capital Costs

Diesel Units

The reference all diesel plan provides for periodic additions of new 600 kW units. These are assumed to be located at the site of the existing generating station, thus site development storage and water supply changes will be less than for a new station. The capital cost of a new plant has been assumed as $ 1 904/kW (source NCPC); this amount covers the cost of the building, machinery, installation and freight. The expenditure for each unit will occur over 2 years,

Year 1	55%
Year 2	45%

on power at end of year 2.

Coppermine Hydro

The optimization studies considered four alternative schemes and installations. As described in Section 8 the estimated capital costs (exclusive of required environmental/feasibility studies) for these alternatives are;

Scheme	Installation kW	Capital Cost $	Cost $/kW
1	922	12 112 000	13 136
2	1 888	17 887 000	9 474
3	2 243	19 548 000	8 715
4	2 800	22 668 000	8 095

The above capital costs include interest during construction (IDC) at 8%. For the anayalses using a range of discount rates the IDC amounts were deleted and capital expenditures applied on an annual basis using the following schedule of disbursements.

Year	Scheme 1	Scheme 2	Scheme 3	Scheme 4
1	23,3	20,6	20,2	19,6
2	39,3	43,1	43,7	44,8
3	37,4	36,3	36,1	35,6
	100,0	100,0	100,0	100,0

on power is assumed at the end of year 3.

11.5 HEATING LOAD CREDIT

The selection of the optimum installation was based on comparison of four alternative installations (Section 9.6). All these comparisons included a credit for the use of surplus hydro energy to meet the heating load, i.e., by displacing part of the fuel oil consumption for heating.

This calculation was made on a present worth basis using year by year useable energy surpluses. The annual useable surplus energy amounts were calculated on an interval basis as the difference between the available interval hydro energy at the electrical demand, up to the interval heating demand.

As is seen from figure A-9.2 the summer heating and electrical loads are low. Consequently for all alternatives, and throughout the evaluation period, a significant portion of the hydro energy cannot be used for electrical supply or for heating.

The cost of fuel for heating is based on 56 cents/litre. The equivalent electrical cost is 7,125 cents/kWh. An accepted standard for the valuation of electrical energy for heating is to assume a value of 90% of the equivalent electrical cost, i.e., 0.9 x 7,125 or 6,41 cents/kWh. This value was applied to all surplus hydro generation that was useable (i.e., not in excess of the heating demand).

The present worth of the annual heating credits which were discounted at the same rate as the costs provide the gross benefit from the displacement of heating fuel. This was reduced by the cost of adding heating units, which was assumed to be $2 200 per household (source NCPC).

Although the availability and useability of energy in excess of the electrical demand will vary over the evaluation period, an approximate allowance for conversion costs was assumed based on the provided average number of households to be supplied.

Costs assumed the following household heating conversions up to the limit of the existing number of buildings, namely 245.

Scheme	Installation kW	No Households
1	922	93
2	1 888	245
3	2 243	245
4	2 800	245

It must be noted here that heating credit using waste heat from the diesel plants was not considered, since this kind of benefit is being examined in another study sponsored by Energy Mines and Resources.

11.6 COMPARISONS AND RESULTS

The above subsections have described the general scope and approach to the evaluation of the economic viability of the Coppermine project, and have provided information on the base data used for the analyses.

The results of the optimization and project evaluation studies are described as follows.

11.6.1 Project Optimization

The optimization analyses have been carried out to define the project installed capacity and preferred on power date to yield maximum net benefits.

Installation Optimization

As part of the generation planning studies carried during the final stage of the study program, an optimization study was carried out based on net benefits calculated from system cost comparisons for a series of installations and plant sizes.

The procedure is the same as for the evaluation studies. Benefits were calculated as the difference in the present worth of system costs with and without the hydro project, including the heat load credit.

The basic analysis was to calculate the net benefits for a range of installations, thereby defining the installation that provides the maximum net benefit. This is the point at which the marginal benefit cost ratio is equal to 1,0.

The cost comparisons were made using the base case load forecast and generation plans, as described in Section 9.3.

The optimization studies covered a range of installations and discount rates, as follows.

Scheme	Installation kW	Capital Cost $000
1	922	12 112
2	1 888	17 887
3	2 243	19 548
4	2 800	22 668

Cost of Feasibility and Environmental Studies (1986)	$1 000 000
On Power Date	December 1990
Discount Rates	6, 8 and 10%
Fuel Prices	Reference fuel prices: 54 cents/litre for diesel fuel 56 cents/litre for heating oil

For Scheme 1 a revised generation plan was prepared that provided for additional diesel installations and retirements after the capability of the hydro plant is fully utilized to meet the electrical load.

Schemes 2, 3 and 4 will provide excess generation, hence later diesel installations are not required and no retirements are assumed as the existing diesel operating hours will be minimal.

The derived net benefits, as a function of discount rate and installation size, are shown in figure A - 9.3. The corresponding Benefit/Cost Ratios are as follows.

Scheme No	Installation kW	Benefit/Cost Ratio vs Discount Rate 6%	8%	10%
1	922	1,40	1,05	0,85
2	1 888	1,46	1,13	0,89
3	2 243	1,44	1,08	0,86
4	2 800	1,32	1,01	0,79

These comparisons show that for all discount rates tested, scheme 2 is the optimum. It may also be noted that the results are not overly sensitive to the selected installation. Consequently the finally selected installation could be varied from the indicated optimum, if justified by economies due to equipment selection, as may be defined in more detailed studies.

On Power Date

The second parameter tested in the optimizations studies was the on power date. Comparisons of benefits and costs were made for on power dates between 1990 and 1993, using the costs and energy characteristics developed for the 1 888 kW, Scheme 2.

The parameters used in the analyses were:

Installation	1 888 kW (at the plant)
Annual Energy	14 800 MWh (delivered)

Project cash flow (1984 $)

Year 1	$ 2 920 000
Year 2	7 944 000
Year 3	5 219 000
Total	$16 083 000

Environmental and Feasibility studies	$ 1 000 000
On Power Date	At start of year
Load Forecast	Medium combined load
Discount Rates	6, 8 and 10%
Fuel Prices	Reference fuel prices: 54 cents/litre for diesel fuel 56 cents/litre for heating oil
Generation Plan	As given in Section 9.3.4 except with the alternative hydro on power dates

As for the optimization of the installed capacity, the comparisons were based on total system costs, with an adjustment for the use of surplus hydro generation for heating.

The analyses yielded the following Benefit/Cost Ratios, as a function of on power date and discount rate.

Comparison of On-Power Dates for Scheme 2
Benefit/Cost Ratio vs Discount Rate

On-Power Year	6%	8%	10%
1990	1,46	1,13	0,89
1991	1,52	1,15	0,92
1992	1,54	1,17	0,93
1993	1,47	1,12	0,88

The results show that the net benefits are maximized with an on-power date of 1992 (January), irrespective of the discount rate. Net benefits are also maximised for discount rates of 8% and 10%. For a 6% discount rate net benefit is maximised with a 1991 commissioning. No tests were made to determine if a variation in fuel price or load growth would affect this conclusion.

Conclusions

The optimization comparisons have shown that the Coppermine hydroelectric project, if implemented, should

- be sized for an installation of about 1 900 kW
- be scheduled for an on-power date of about January, 1992, based on the reference load forecast and fuel prices.

11.6.2 Reference Case Comparisons

The reference case, as developed from the optimization studies, assumes that,

- the project has an installed capacity of about 1 900 kW
- the on power date is early 1992

The results of the primary comparisons, that is using the reference fuel prices and load growth forecast, are summarized as follows, based on analyses at 1984 constant price levels.

Breakeven Rate of Return (IRR) 9,5%

Benefit/Cost Ratios	Interest Rate %	B/C Ratio
	6	1,54
	8	1,17
	10	0,93

Supplementary results include the payback period and average generation costs. These were derived with and without the credit from use of surplus electrical energy for heating (after allowing for heating unit conversion costs). These values are calculated at a discount rate of 8%.

Payback Period	20 years, if surplus energy is used for heating
	40 years, without use of surplus energy for heating

Average Generation Costs	Unit Costs in cents/kWh
All diesel generation	37,8
With the hydro project:	
- Average system costs, including heating credit	33,6
- Average system costs, excluding heating credit	41,2
- Hydro generation costs, including heating credit	31,7
- Hydro generation costs, excluding heating credit	43,4

The results show, the importance of the heating credit in establishing the economic viability of the hydro project.

The general conclusion from the base case comparison is that the economic viability of the hydro project is largely contingent on,

- the use of surplus hydro generation for heating,
- the future (relative) prices of distillate and heating fuels,
- the operational requirements to maintain existing diesel units in service, if the hydro project is implemented.

11.6.3 Sensitivity Tests

To further define the sensitivity of the hydro project's economic viability to the various input assumptions, the following sensitivity tests have been carried out.

- Fuel Price
  A scenario has been assumed whereby diesel distillate and house heating fuel will increase in price by 2% annually after 1990, relative to all other costs which are retained at 1984 price levels.

- Capital Costs
  Comparisons have estimated the IRR values that would result from assumptions that the actual cost of the hydro project is (at 1984 price levels) above or below the reference estimate. The cases which were examined are

  - reference estimate as given in Section 8
  - reference estimate ± 10% increase in the capital cost
  - reference estimate + 20% increase in the capital cost

- Load Growth
  Comparisons have been carried out to show the effect of assuming the low load growth on the selection of the plant installed capacity on the IRR for the project.

These analyses, except the tests with the low load forecast, all assume the reference Scheme 2 (1 888 kW), the medium combined load forecast and the reference 1984 fuel prices (except as noted above).

The results of the analyses to test the effect of fuel price and capital cost, expressed in terms of the present worth of net benefits as a function of discount rate, are shown in Figure A - 9.3, and are summarized as follows.

Case	Breakeven Real Discount Rate (IRR) %	
Reference Case Comparison	Include $1 million for feasibility	9,5
With 2% Escalation in Fuel Cost		10,1
With Hydro Capital Cost +10%		8,7
With Hydro Capital Cost -10%		10,3
With Hydro Capital Cost +20%		7,9

These results show that, within the range of variation in fuel cost and capital cost, the hydro project would achieve an internal rate of return between 7,9% and 10,1% as compared with the decision discount rate of 8%.

The same results, expressed in terms of Benefit/Cost ratios for real discount rates between 6 and 10% are given below. For the cases of +20% increase in the capital cost and 10% discount rate the benefit cost ratio is generally below 1,0:

Case	Benefit/Cost Ratio vs Real Discount Rate 6%	8%	10%
Reference Case with Allowance of an Additional $1 Million for Studies	1,54	1,17	0,93
With 2% Escalation in Fuel Cost	1,68	1,28	1,01
With Hydro Capital Cost +10%	1,41	1,07	0,85
With Hydro Capital Cost -10%	1,70	1,29	1,03
With Hydro Capital Cost +20%	1,29	0,93	0,78

For the test with the reduced load growth forecast, the hydro plant scheduling is not changed (Section 9.3). Consequently for the hydro plan the capacity and energy capabilities, together with the investment requirements, remain the same as in the base case comparisons.

The installation dates for new units in the diesel plan after 1993 are delayed by 11 years, with a corresponding defernment in capital expenditure.

Benefits from the hydro project are reduced as the energy demands, and hence opportunities for diesel fuel replacement, are less with the low load growth. However this is slightly offset by a marginal increases in the credit for sales of surplus energy for heat.

The results of the comparions for the low load growth scenario are summarized as follows.

Breakeven Internal Rate of Return		8,2%	(9,5%)
Benefit Cost Ratios	I	B/C	
	6	1,34	(1,54)
	8	1,02	(1,17)
	10	0,80	(0,93)

( ) Results with the median load growth

The tested load growth scenario in effect assumes that the hydro project is committed now, on the basis of the median load growth, and that actual benefits are based on reduced electrical energy demands.

The further approach of assuming the low load forecast as the reference case, for project sizing and the selection of on power date, has not been tested.

11.7 Evaluation of Wind Alternative

From the results which were obtained in this section and Section 10, it is apparent that Coppermine is not a suitable site for the installation of wind generators, from the following view points:

- the wind regime is too low;
- the cost of energy is more than from either the diesel generators or the hydro scheme.

SECTION 12 - IMPLEMENTATION GUIDELINES

Before the hydroelectric project at Bloody Falls can be studied to a feasibility level or designed, there are certain preliminary investigations which must be carried out. These are listed below and discussed.

Electrical

Hourly data of electrical consumption at Coppermine for at least one year should be collected. It would also be useful if a conservation pilot study could be done.

Environmental

Baseline information on the fish in the Coppermine river is needed. In Section 10-6 the type of study which is needed was outlined and a cost estimate given.

Geotechnical

In estimating the cost of the tunnel, assumptions were made regarding the nature of the rock which would be encountered. Figure A - 7.2 shows the locations where boreholes should be drilled. It is recommended that there should be six boreholes inclined at 30° and taken 7m below the tunnel invert or below the powerhouse (BH5). The geotechnical investigations are primarily to obtain data concerning ice behaviour and the data to enable tunnel support and lining requirements to be better assessed.

Hydrology

The gauge which has been established upstream of the falls by Water Survey of Canada must be maintained and more flow measurements must be taken to establish a proper rating curve. In addition, another gauge should be erected just downstream of the falls and another rating curve established. Both gauges should be tied to the same datum so as to obtain the variation of head with flow. In other words, data to plot a flow duration and a head duration curve must be obtained. The latter curve is needed to select a proper design head for the turbine.

It is also necessary to make sediment measurements since the interception trough can trap sediment and make the intake inoperative.

Topography

In addition to having ground surveys, the topography in the immediate vicinity of the falls requires that new ground controls, vertical and horizontal, should be established and new air photographs should be taken. New and better maps of the site can thus be prepared.

SECTION 13 - CONCLUSION AND RECOMMENDATIONS

13.1 CONCLUSIONS

This prefeasibility study has been carried out to determine the following:

- the projected normal electric load and heating load at Coppermine;
- the technical feasibility of constructing a small hydro project which would have minimal interference with the environment. The capability of the project has been restricted to meet the projected normal electric load;
- the profile of the generating system,
- the economics of the project in relation to alternative generation;
- environmental impact of the project.

Technical feasibility.

It is considered that a run of the river hydro project could be constructed at Bloody Falls to meet the projected load. The project would not involve the construction of a dam across the river, but would entail the construction of a tunnel and semi-underground powerhouse.

Installation

Four schemes were investigated and the most suitable scheme was one with a rated output of 1888 kW. A plant with a nominal output of 2 MW could possibly be installed. The selection of this scheme was based on a comparison of net benefits for a range of installation varying from 922 kW to 2800 kW. The firm and average energy capability of the scheme were identical and equivalent to 15.7 GWh p.a. The energy would be delivered to Coppermine, about 15 km away from the hydro plant, by a 12 kV transmission line.

System profile

Since the hydro plant has only one generating unit, reliability of the electricity supply would have to be achieved by retaining the existing diesel plant. It is expected that the diesel plant would be operated, nominally, for 3% of the time to keep them in a workable condition.

Investment cost

The investment cost of the selected scheme including interest during construction but excluding escalation is as follows:

	1984 Dollars $\$ \times 10^6$
Civil works, including temporary facilities	9,737
Electrical + Mechanical equipment, including transmission costs	3,555
Sub-total	13,292
Engineering and Construction supervision	1,329
Contingencies	1,462
Sub-total	16,083
Interest during construction	1,804
Capital cost	17,887
Feasibility/Environmental Studies	1,000
Total Cost	18,887

Construction schedule

Because of the wide variation in daylight hours and the need to execute construction works in the river during the periods of low flow, the construction schedule requires 34 months to complete the project.

The critical item in the construction schedule is not the civil works, but the manufacture and delivery of the generating equipment.

Project evaluation

Based on the assumption that energy in excess of that required for the normal electric load can be used for heating, and if decision discount rate is 8%, the project is apparently economically viable for a 1992 in service date and can replace the existing diesel generators. The expected internal rate of return is 9,5% p.a. and the payback period is 20 years. A 20% increase in capital cost could reduce the internal rate of return to 7,9%.

For the assumption that excess energy will be used for heating, a comparison of the cost of energy at a discount rate of 8% p.a. shows the following:

Diesel generating system	37,8 ¢/kWh
Hydro - diesel system	33,6 "
Cost of hydro energy	31,7 "

If the excess energy is not sold, the cost of energy from the hydro plant is 43,4 ¢/kWh, and the payback period is extended to 40 years.

The conclusion is that the project is marginally viable for a decision discount rate of 8%, assuming that excess energy can be used for heating.

Environmental impact

Since there is no dam across the river, and the diverted flow is less than the minimum flow in the river, the adverse impact of the project on the environment appears to be minimal both in terms of the aesthetics of the falls and the migration pattern of the fish. However environmental studies will have to be done to determine this.

13.2 RECOMMENDATIONS

The project evaluation results may justify that the Bloody Falls site should be studied to a feasibility level. If it is decided to proceed with these studies a number of preliminary studies should be carried out prior to the main study.

These studies relate to the following:

Environment - The movement and habits of the arctic char must be chronicled

Topography - new aerial photographs and maps of the site must be prepared, including vertical and horizontal controls

Geotechnical - Boreholes along the intake - tunnel - alignment need to be drilled, and permeability tests done.

Load forecast- a pilot study an energy conservation in the community should be carried out.

The estimated cost to carry out these studies is $1 million.

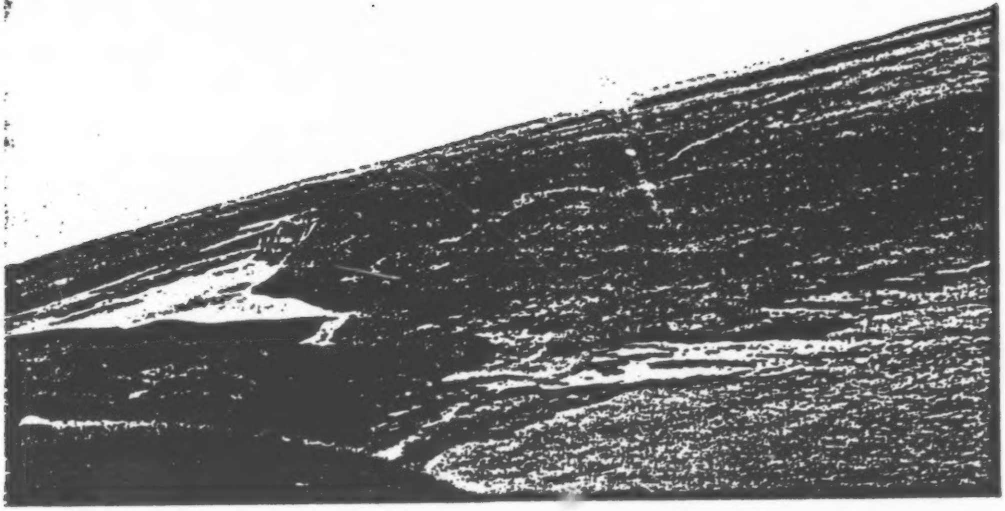


PHOTO 1: Looking upstream. Note delta forming at head of small lake above falls.

PHOTO 2: Middle reach of Bloody Falls. Igneous rock on each bank is highly jointed.

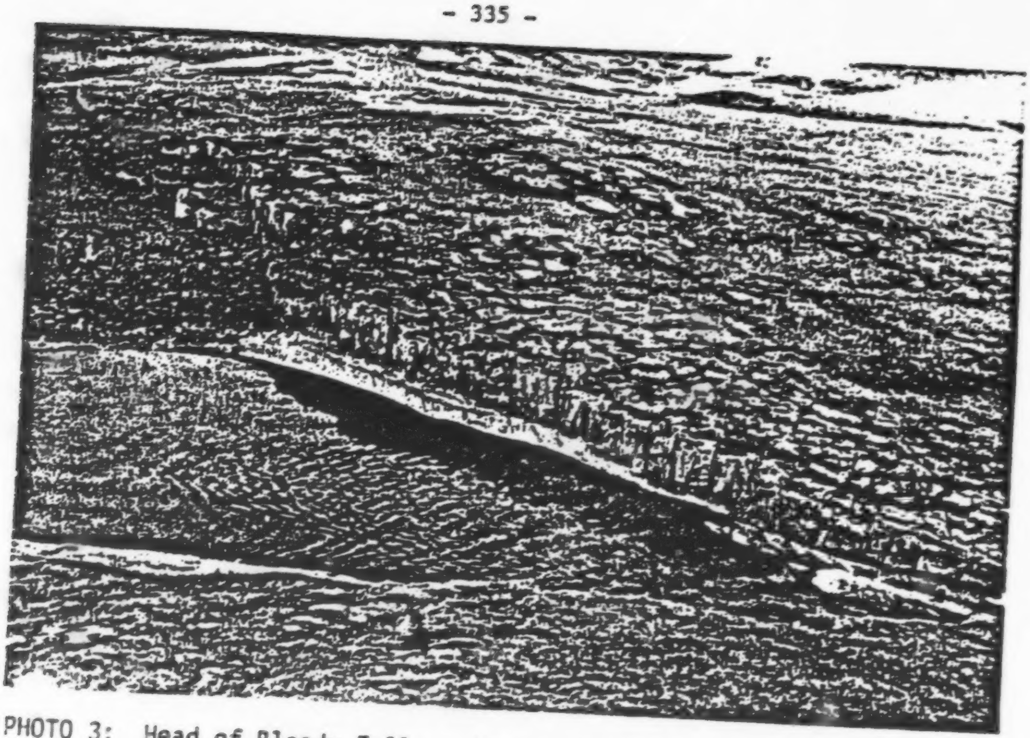


PHOTO 3: Head of Bloody Falls. Meta sedimentary rock at river level and WSC gagehouse on left of photo.

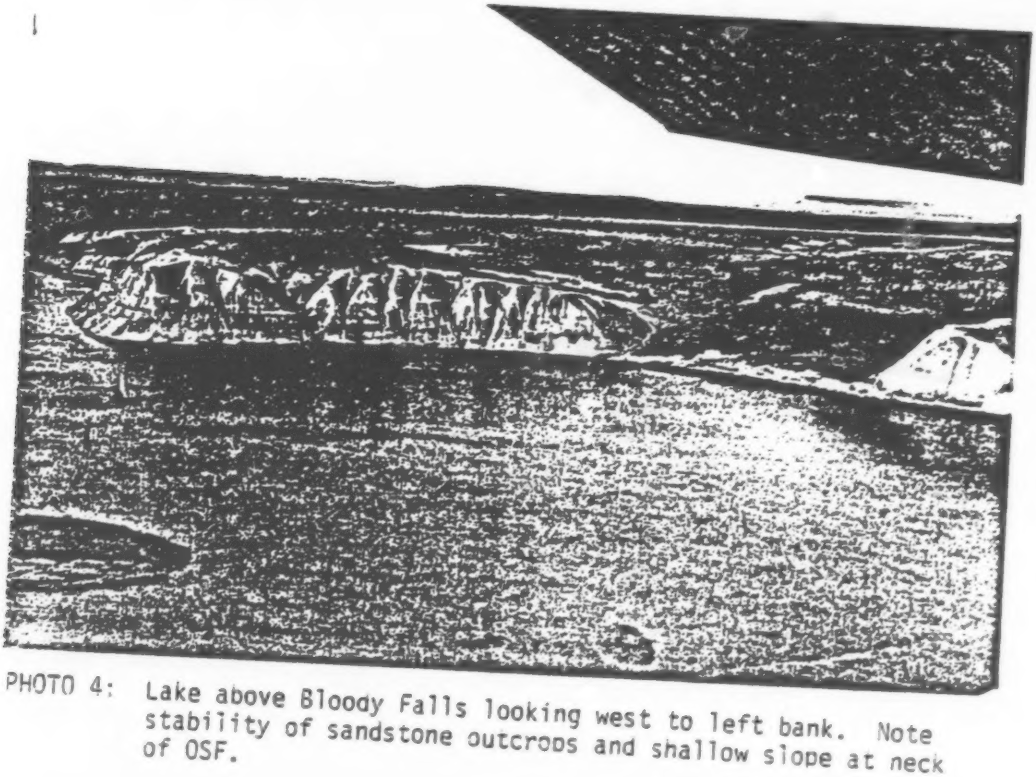


PHOTO 4: Lake above Bloody Falls looking west to left bank. Note stability of sandstone outcrops and shallow slope at neck of OSF.

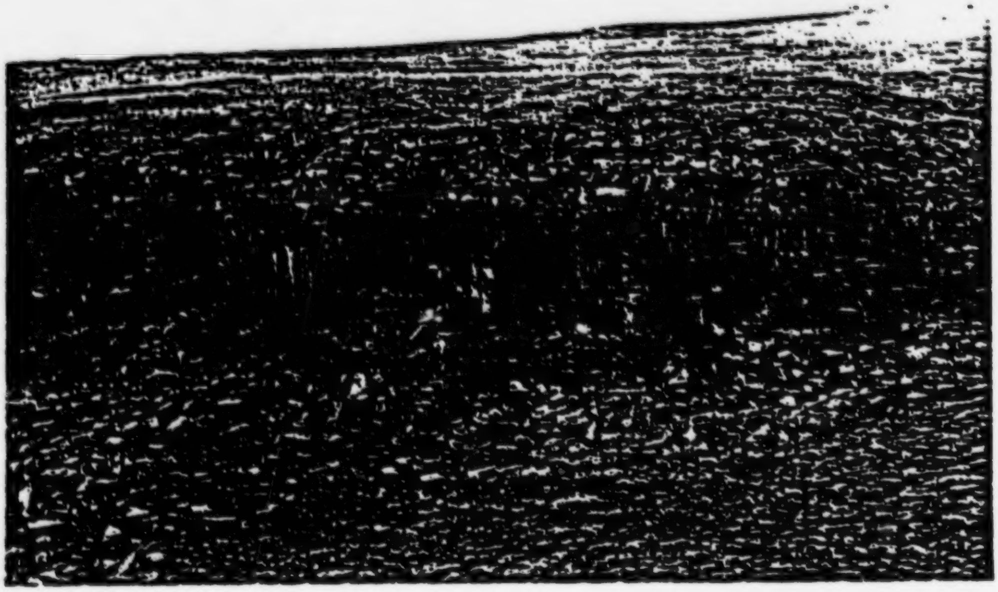


PHOTO 5: Outcrop of igneous rock near left bank above falls. Note frost shattered debris typical of region. Fragments are 1-10 m^3 and good source of rip rap..

PHOTO 6: Bloody Falls right bank. Note columnar jointing in igneous rock and minor overburden of sandy soil.

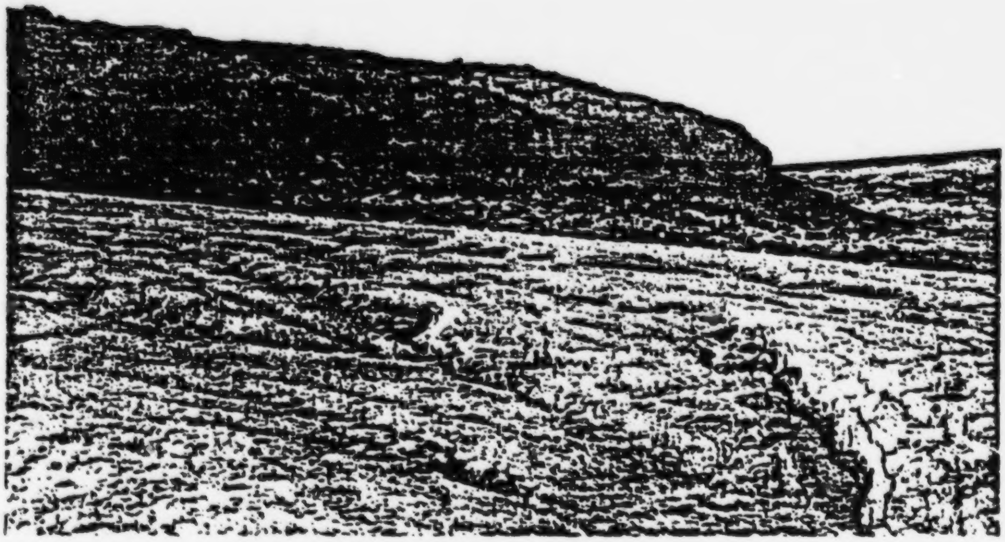
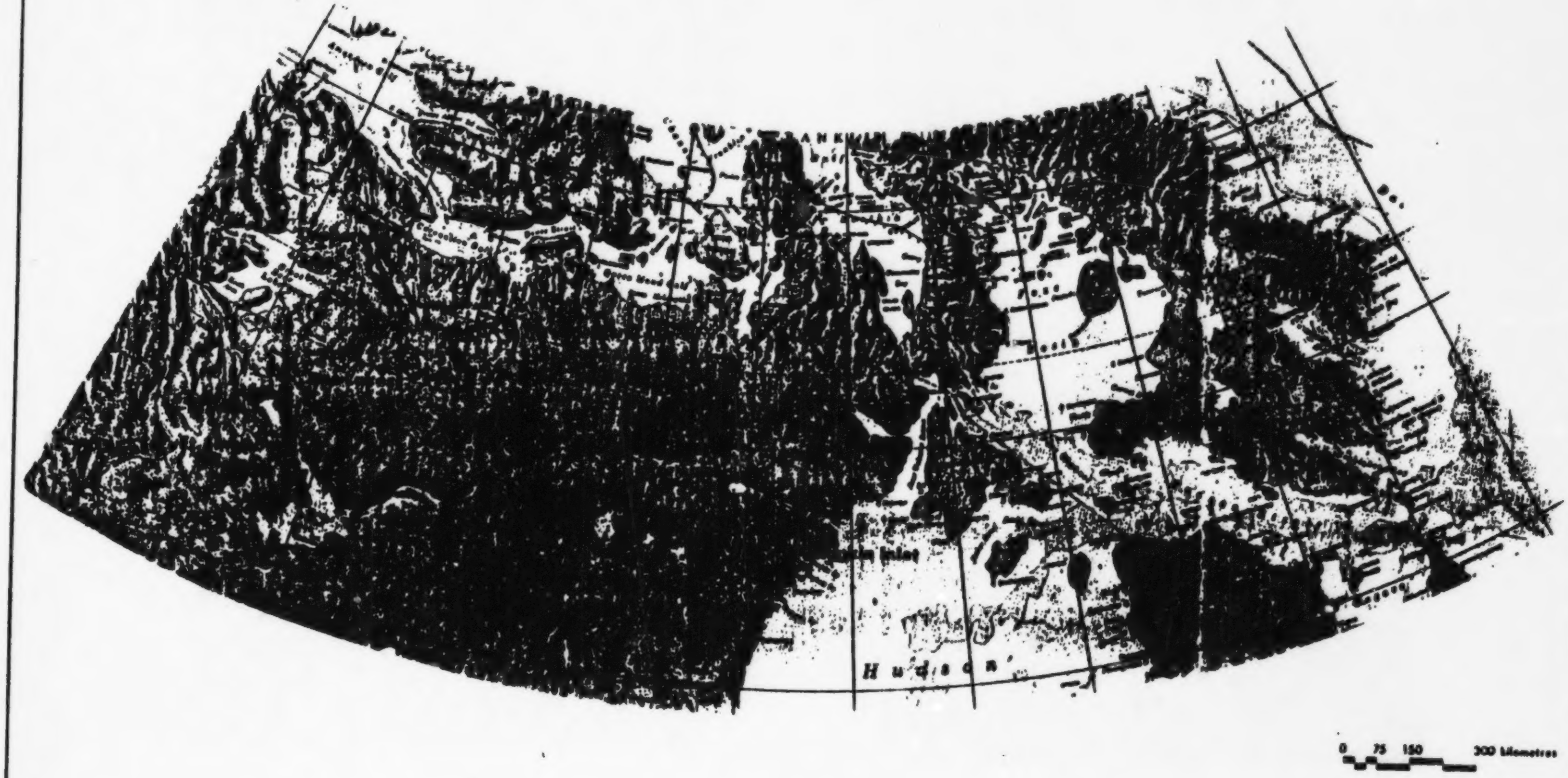


PHOTO 7: Lobe of silt flow from old slide feature on left bank of river upstream of Bloody Falls.

PHOTO 8: Outcrop of gabbro at foot of Bloody Falls - left bank.

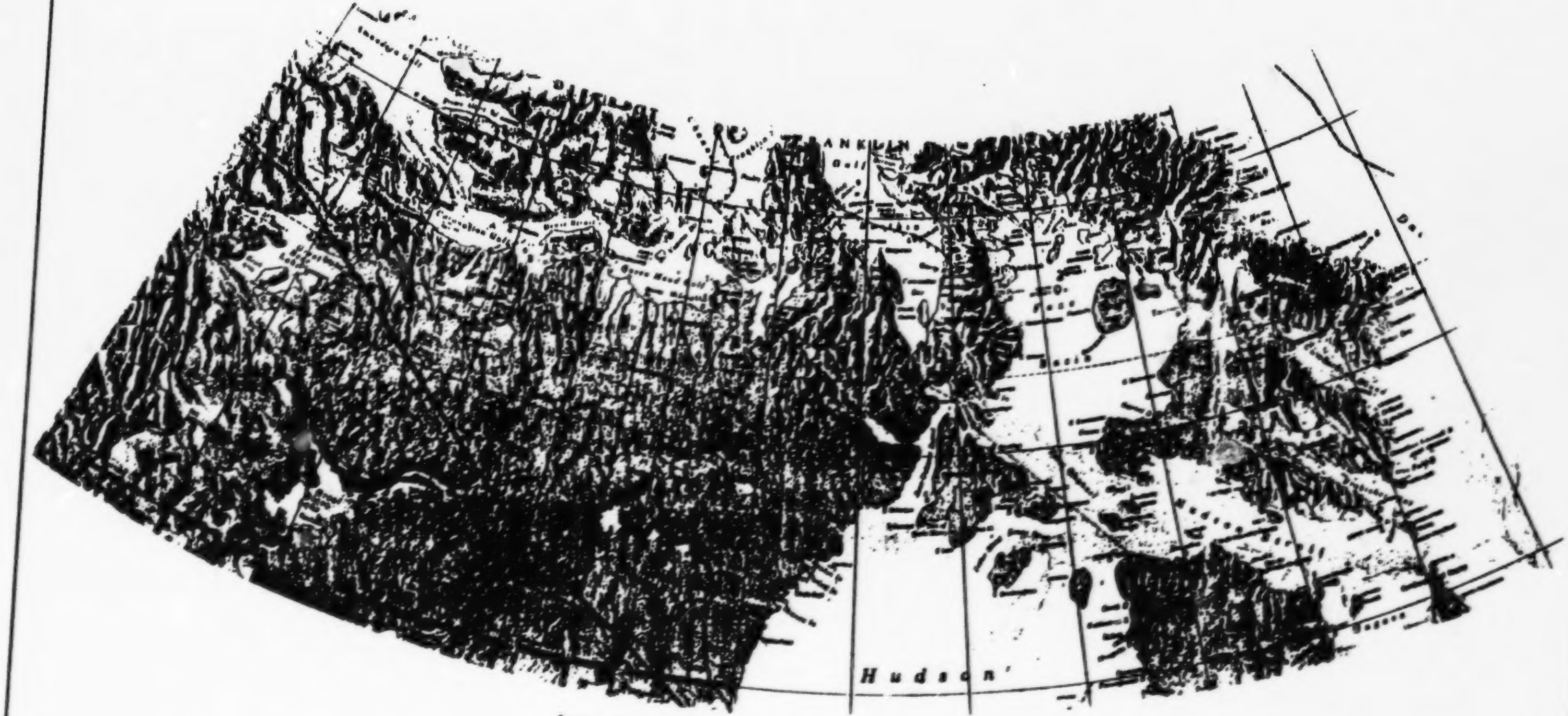
FIGURE A-1.1


Hudson
0
75
150
300 kilometres

hydrowest consultants inc.

LOCATION OF STUDY AREAS

FIGURE A-2.1



Source: N.W.T. Water Resource Study, Acres Ltd., 1976

LEGEND

- — — SOUTHERN LIMIT OF CONTINUOUS PERMAFROST ZONE
- 〰 NORTHERN LIMIT OF TREES

0 75 150 300 kilometres

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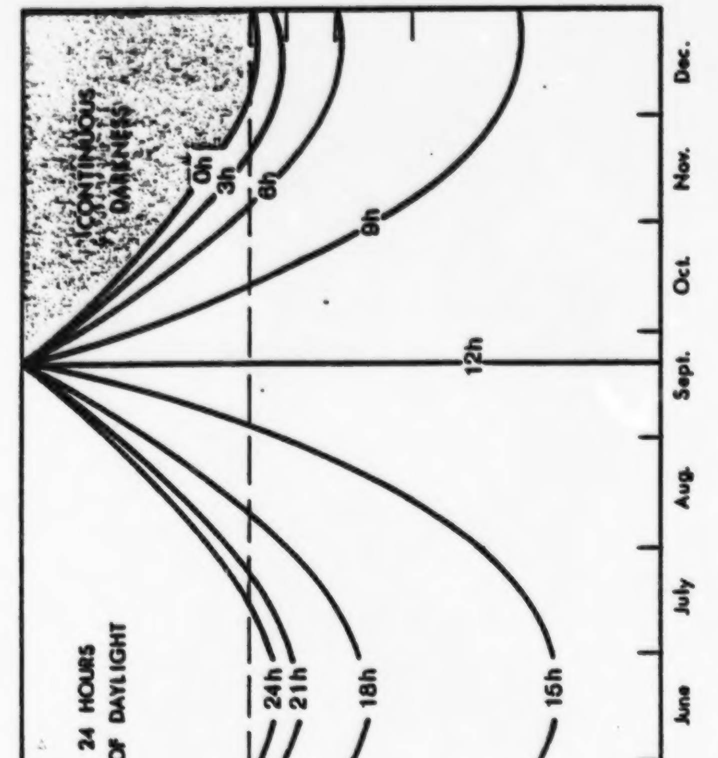
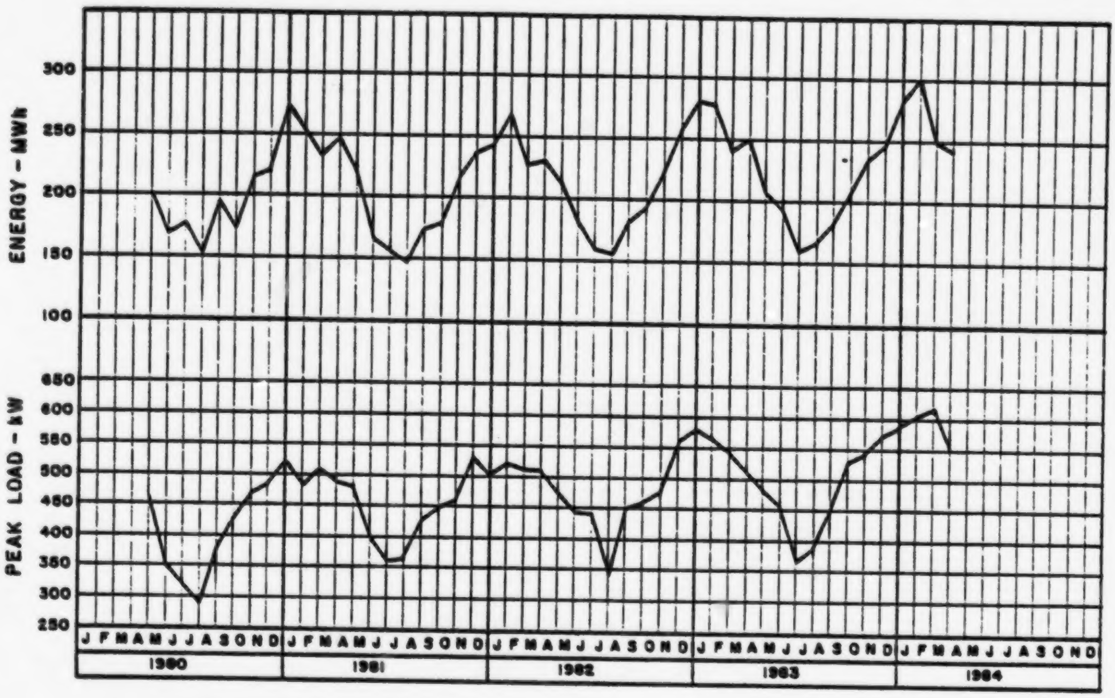
EXTENT OF
PERMAFROST ZONE AND TREE LINE

FIGURE A-2.2



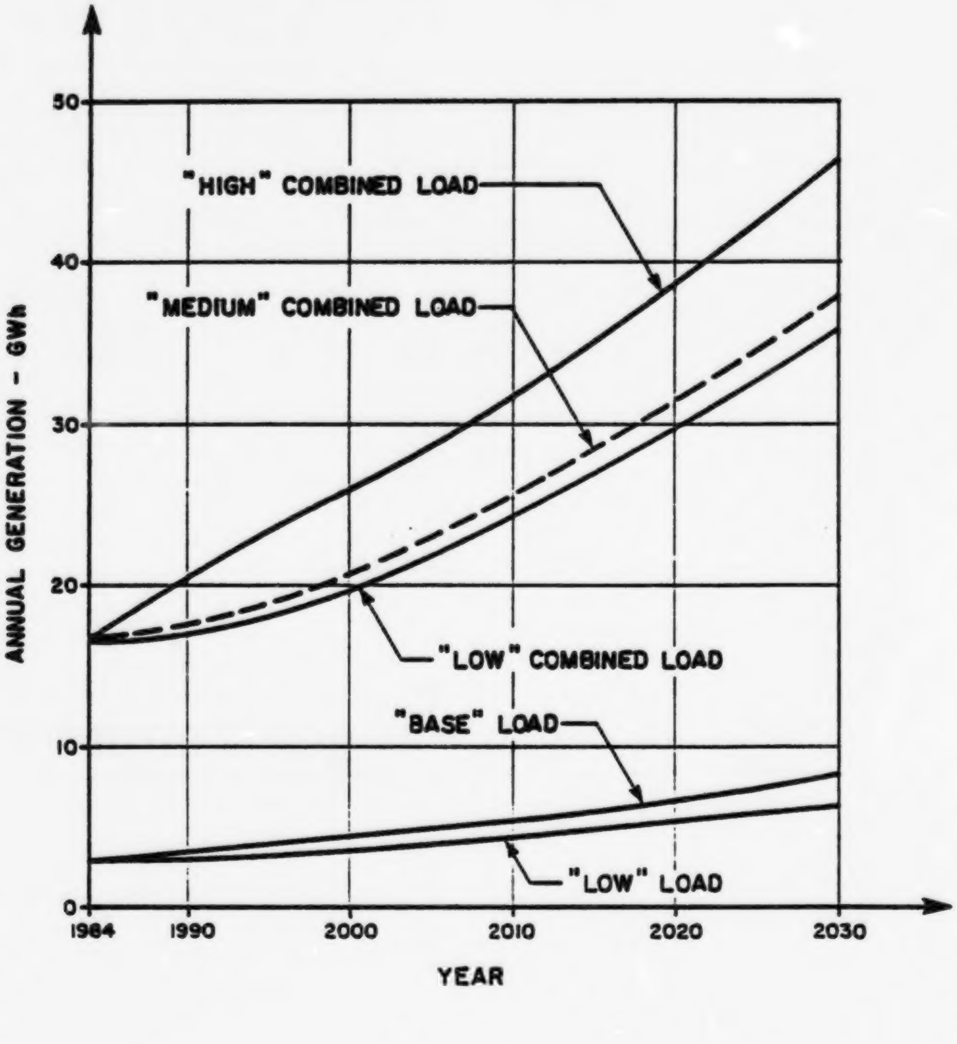
DURATION OF DAYLIGHT HOURS

FIGURE A-3.1



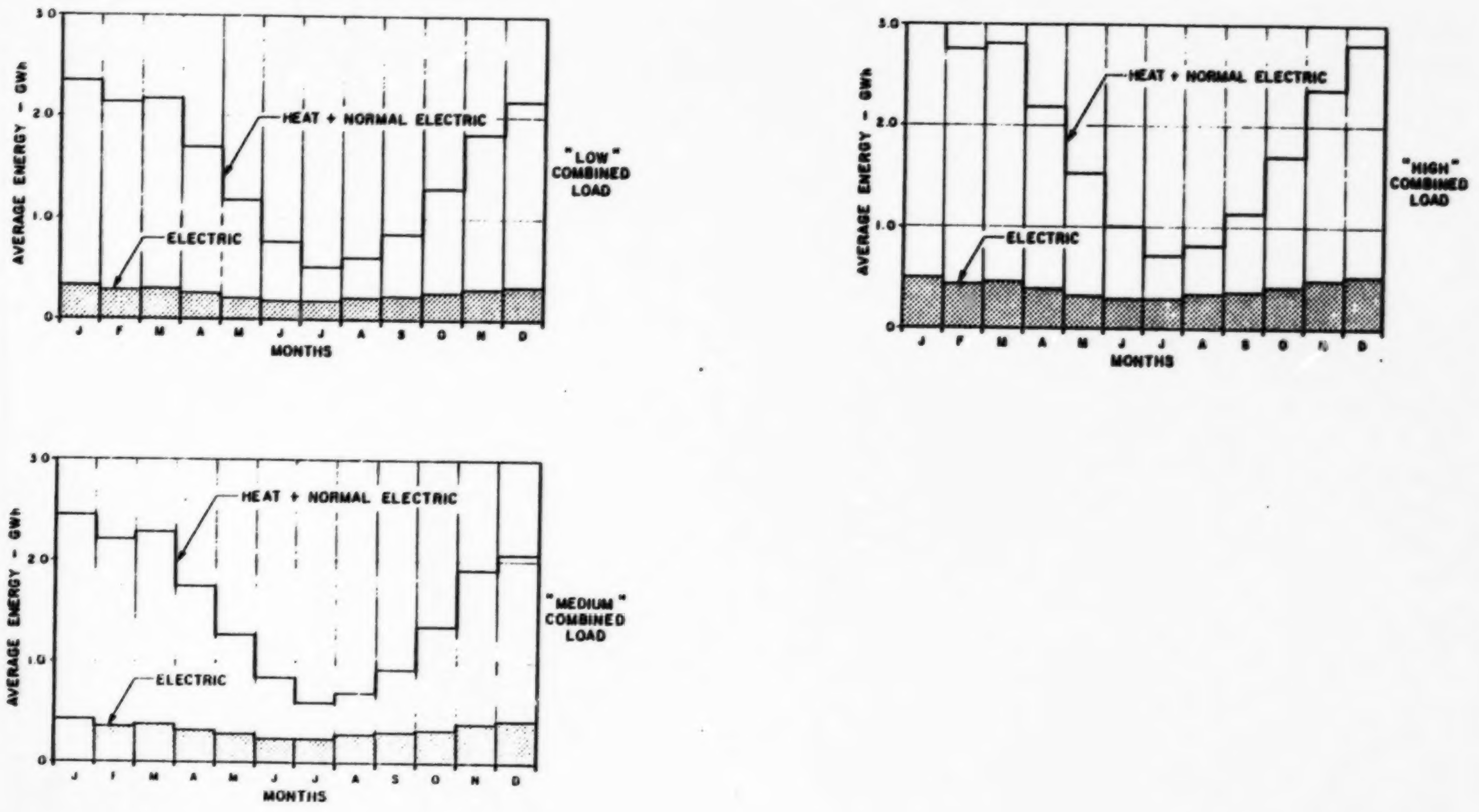
COPPERMINE DEVELOPMENT
HISTORICAL PLANT LOAD

FIGURE A-3.2



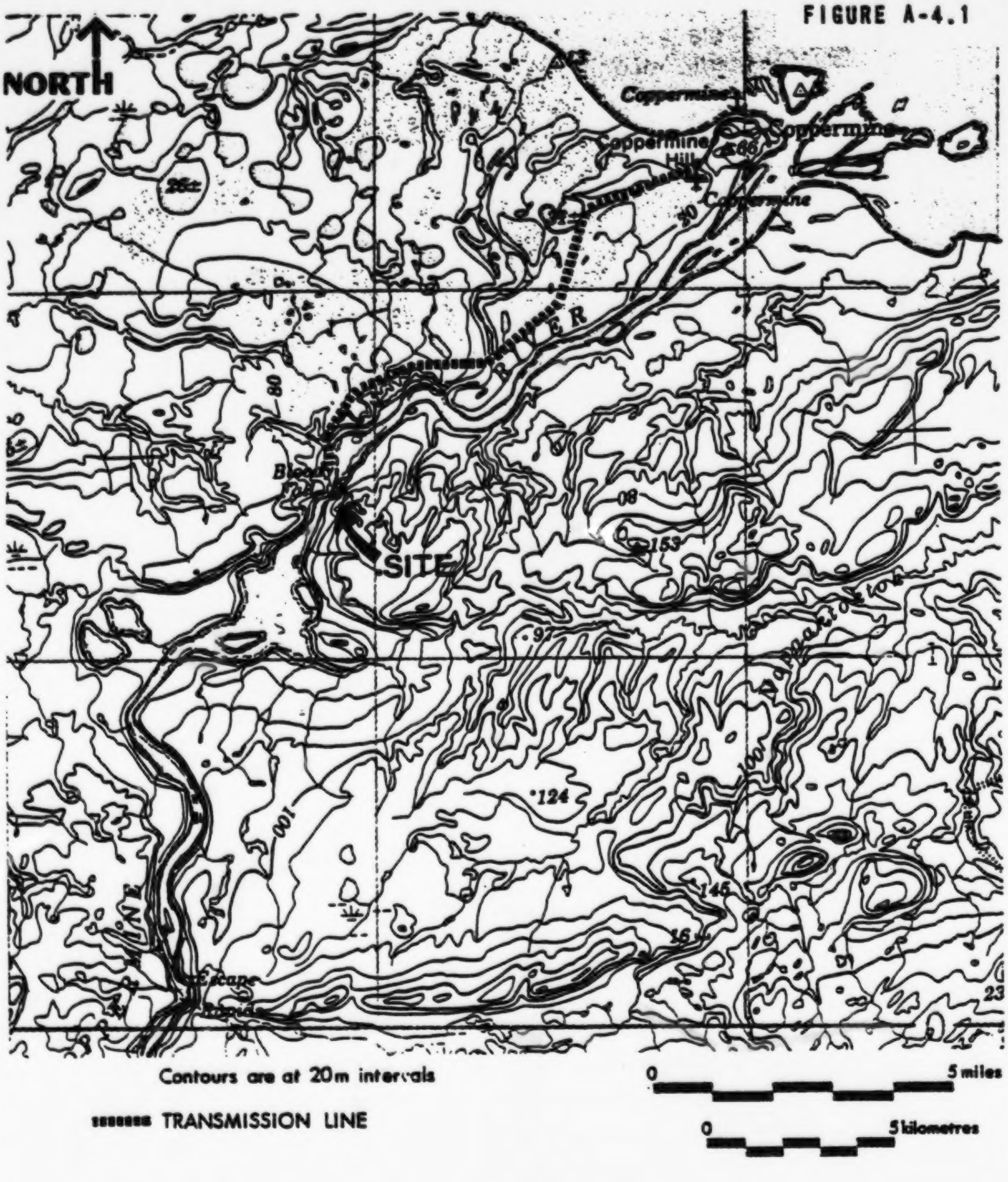
COPPERMINE DEVELOPMENT
LOAD FORECAST

FIGURE A-3.3



MONTHLY LOADS, 1994
COPPERMINE

FIGURE A-4.1

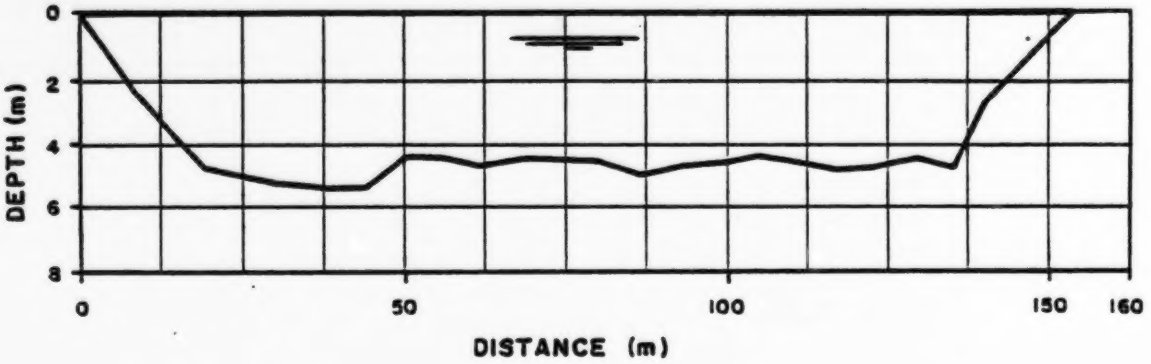

NORTH
Coppermine
Coppermine Hill
Coppermine
Coppermine
RIVER
Bloody Fall
SITE
80
153
124
145
100
Escape Rapids
Contours are at 20m intervals
TRANSMISSION LINE
0
5 miles
0
5 kilometres

hydrowest consultants inc.

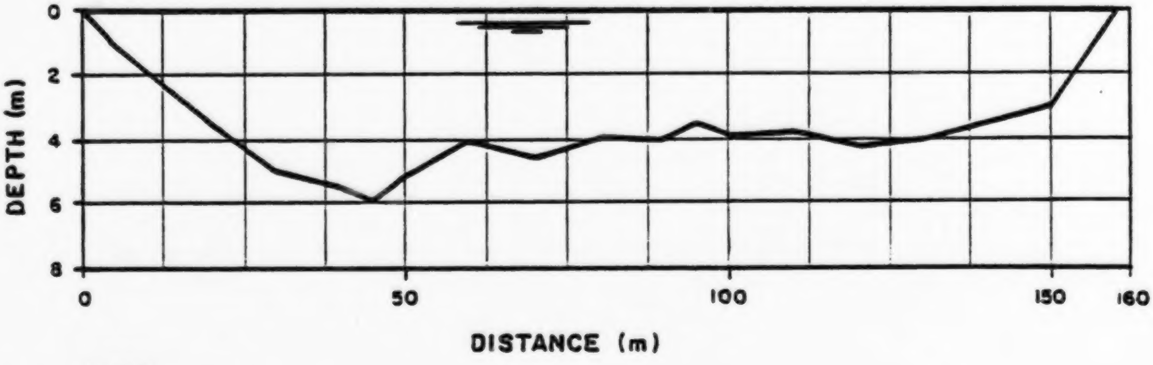
COPPERMINE DEVELOPMENT
SITE PLAN

FIGURE A-4.2

SECTION AT LOCATION OF
WATER SURVEY OF CANADA GAUGING STATION



SECTION 6

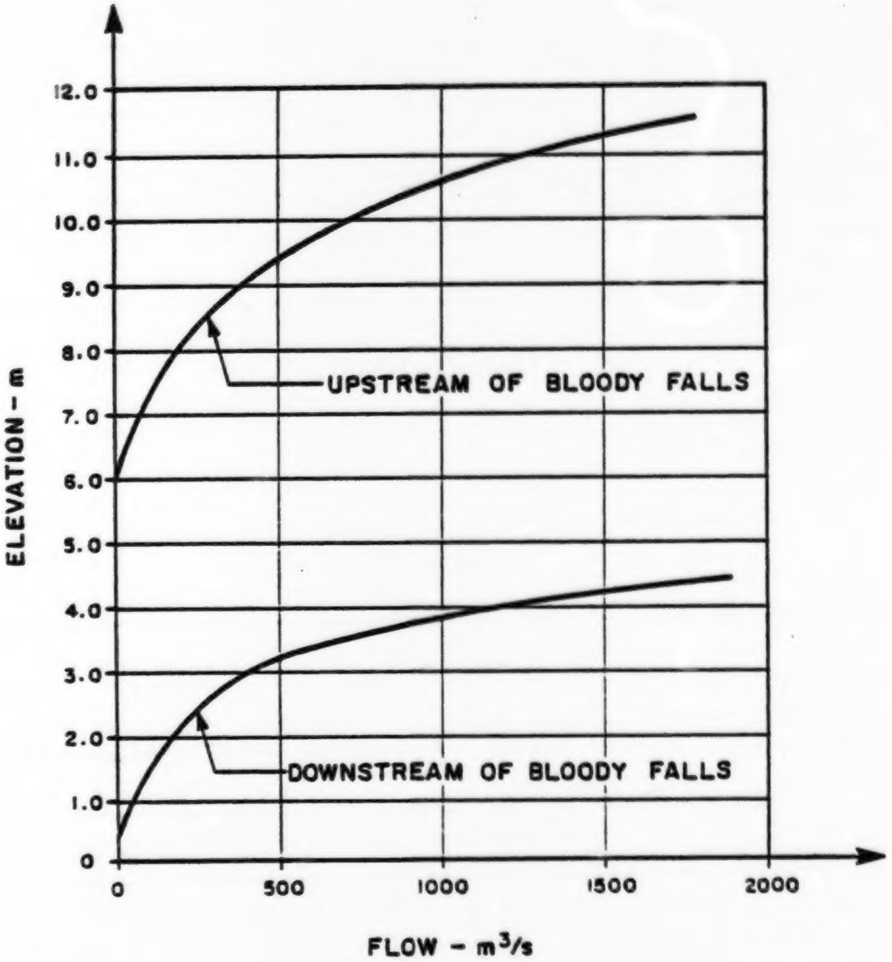


NOTE:

FOR LOCATION OF
SECTIONS SEE
FIGURE A-7.1

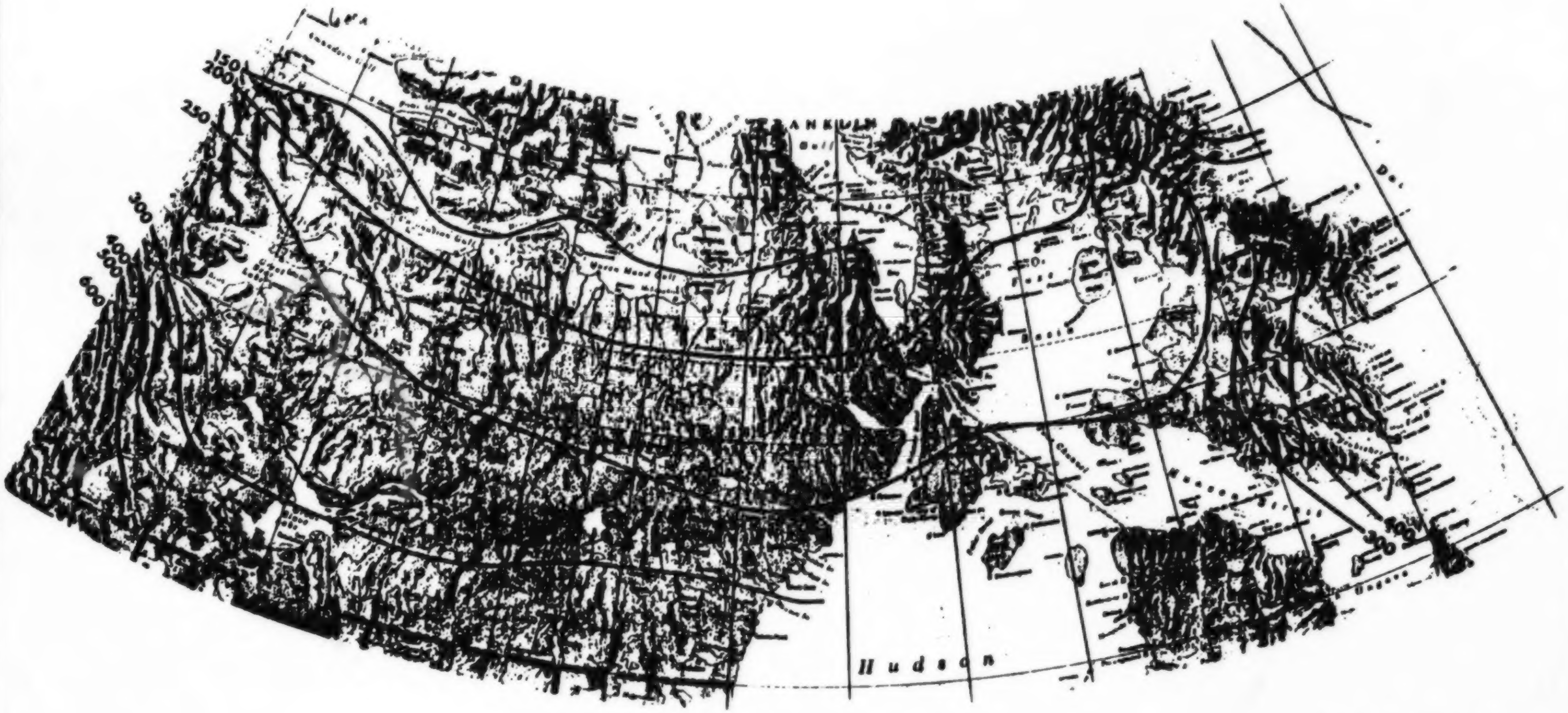
COPPERMINE DEVELOPMENT
CROSS-SECTIONS
ABOVE BLOODY FALLS

FIGURE A-4.3



COPPERMINE DEVELOPMENT
PROVISIONAL RATING CURVES

FIGURE A-5.1


150
200
250
300
400
500
600
FRANKLIN
Hudson
200

Source: N W T Water Resource Study, Acres Ltd., 1976

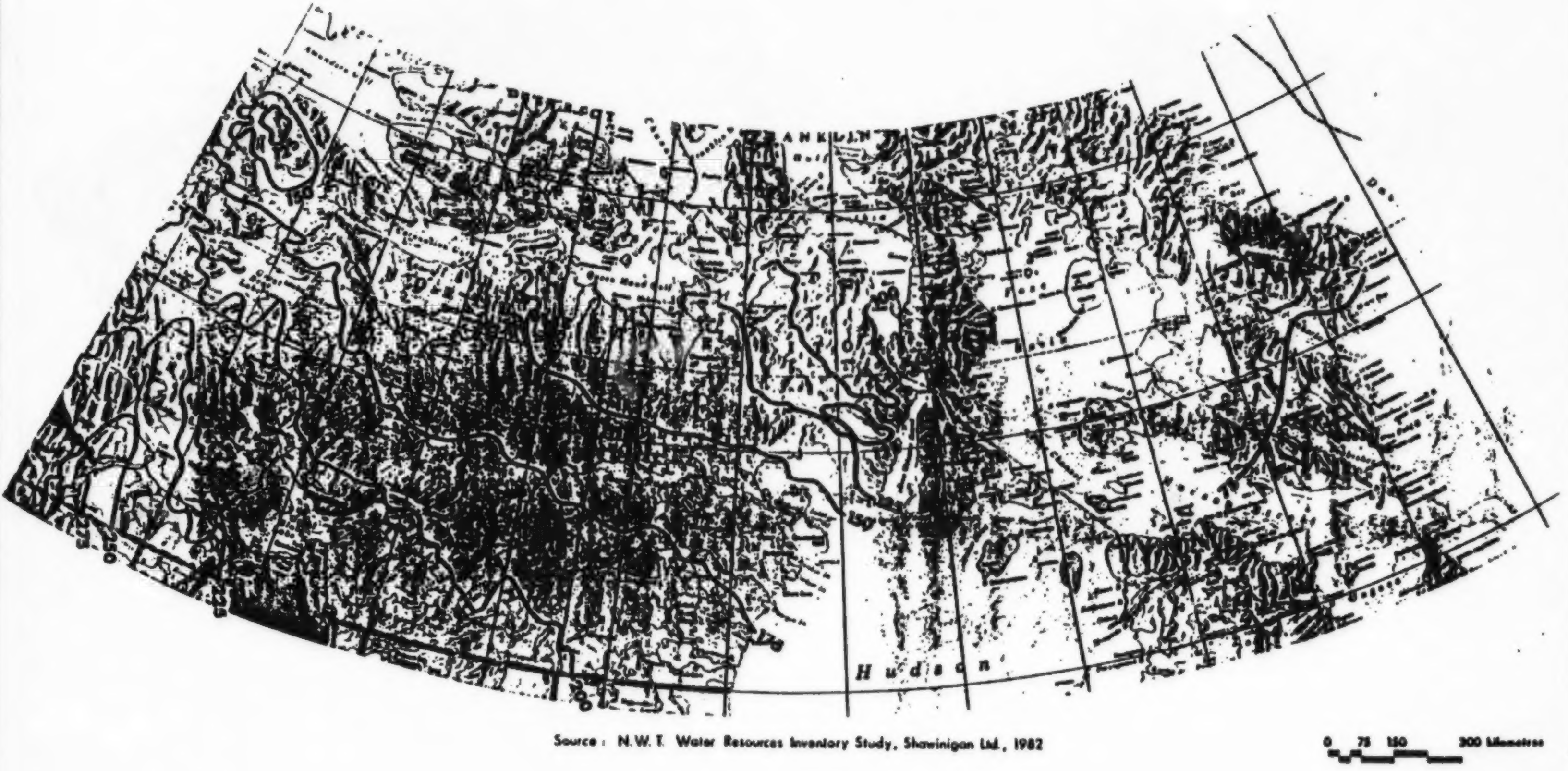
0
75
150
300 kilometres

NOTE: NUMBERS INDICATE mm/yr

hydrowest consultants inc.

REGIONAL ESTIMATE OF
MEAN ANNUAL PRECIPITATION

FIGURE A-5.2


Hudson
150
225
250
275
0 75 150 300 kilometres

Source: N.W.T. Water Resources Inventory Study, Shawinigan Ltd., 1982

NOTE: NUMBERS INDICATE mm/yr

REGIONAL ESTIMATE OF
MEAN ANNUAL EVAPORATION

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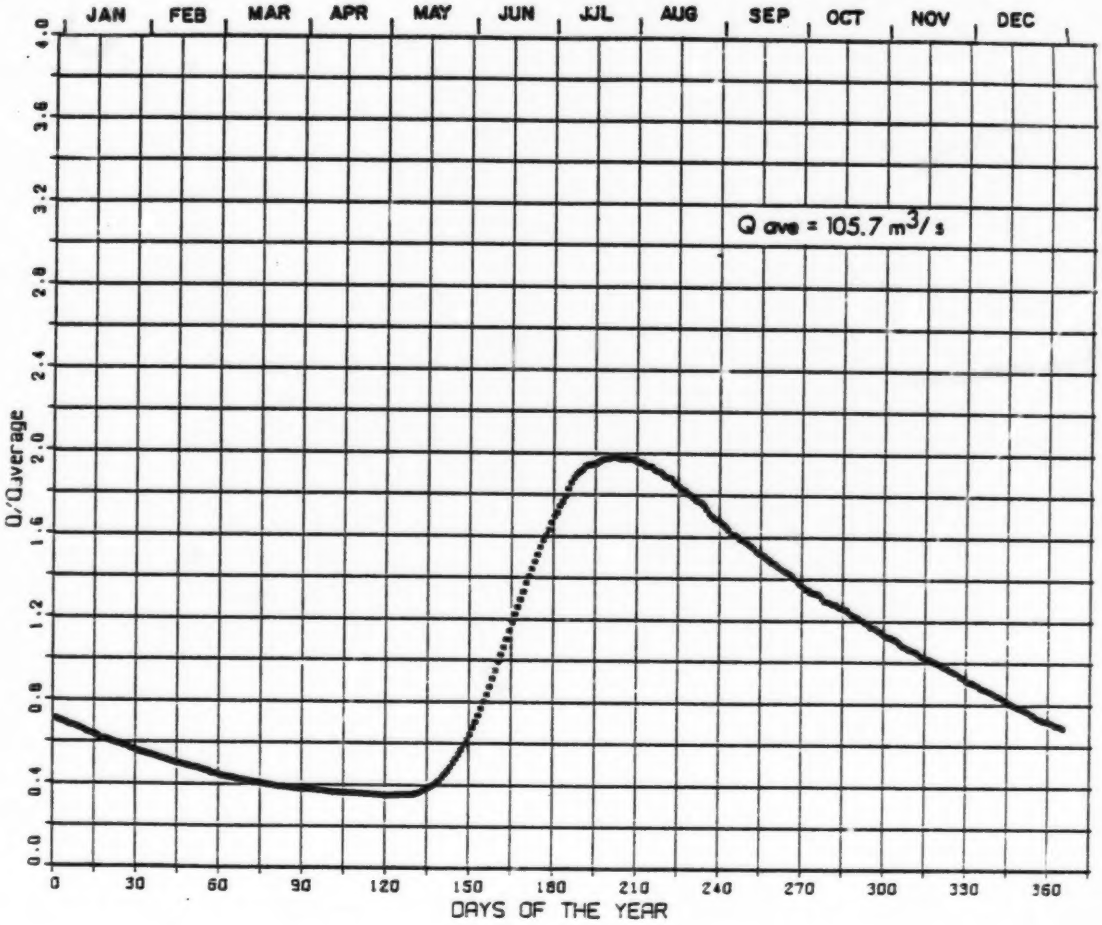
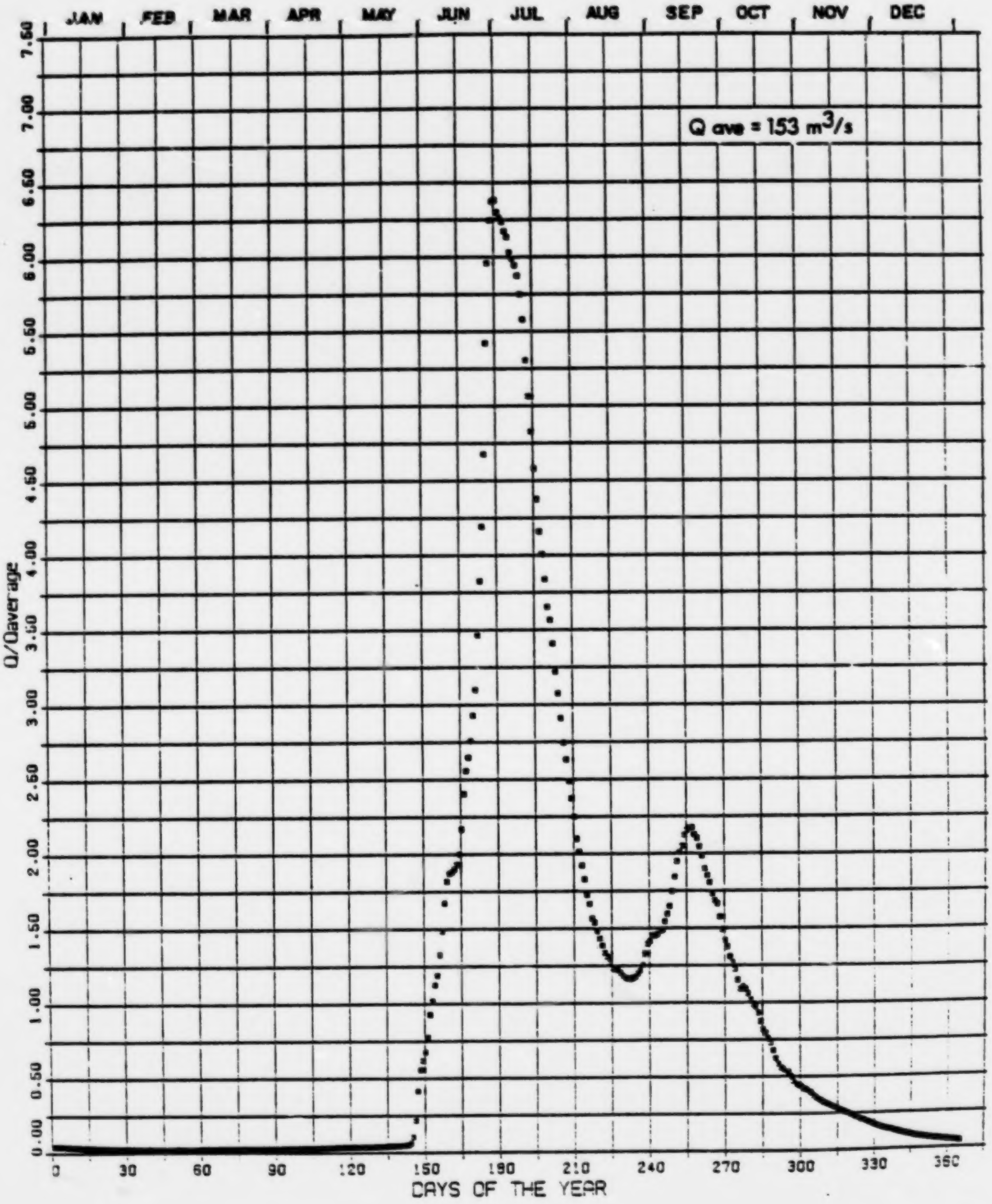
FIGURE A-5.3



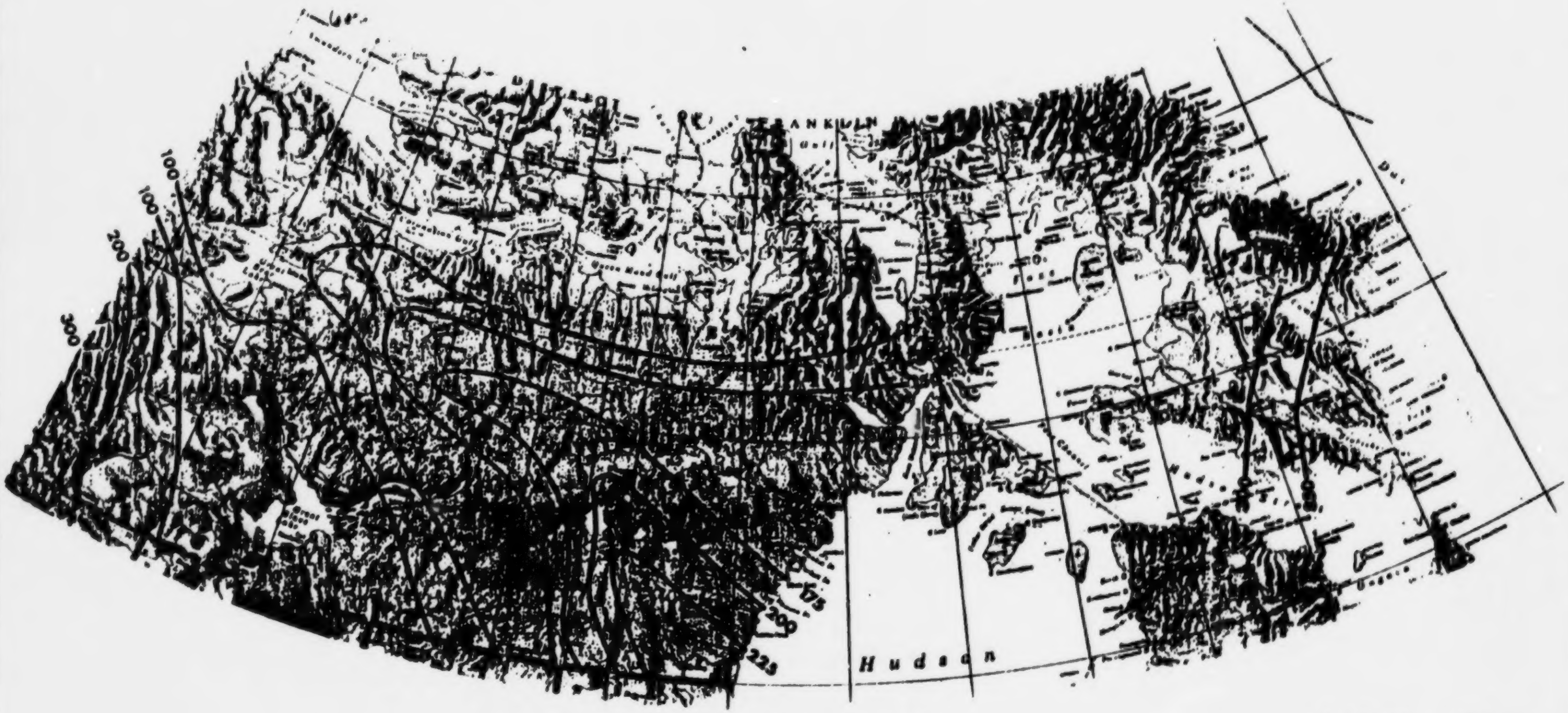
AVERAGE
DIMENSIONLESS DAILY FLOWS
COPPERMINE RIVER AT
OUTLET OF POINT LAKE

FIGURE A-5.4



AVERAGE
DIMENSIONLESS DAILY FLOWS
QUOICH RIVER ABOVE ST. CLAIR FALLS

FIGURE A-5.5


100
100
200
300
175
200
225
FRANKLIN
Hudson
0 75 150 300 kilometres

Source: N.W.T. Water Resource Study, Acres Ltd., 1976

NOTE NUMBERS INDICATE mm/yr

REGIONAL ESTIMATE OF
MEAN ANNUAL RUNOFF

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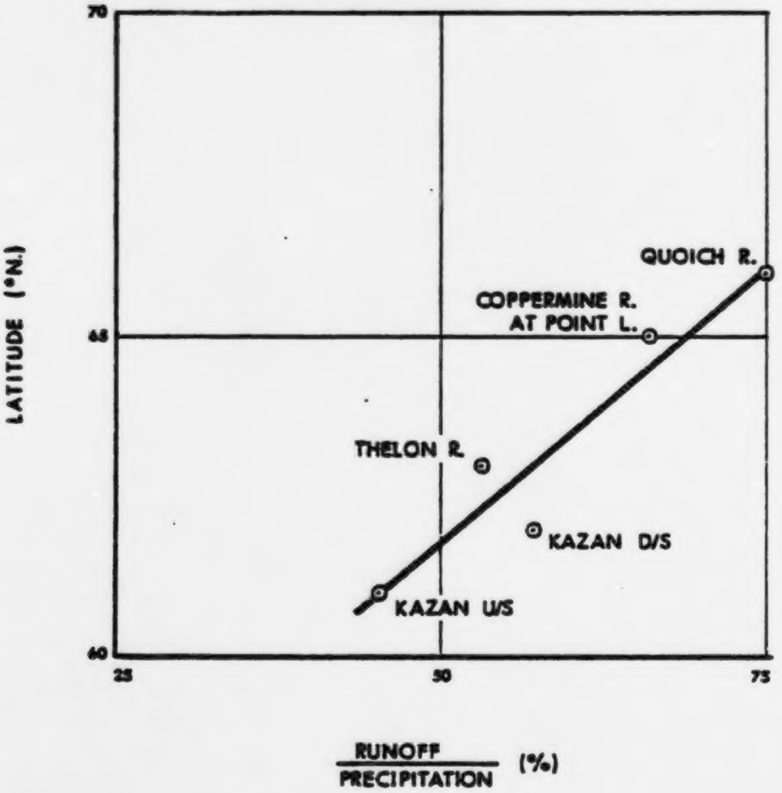
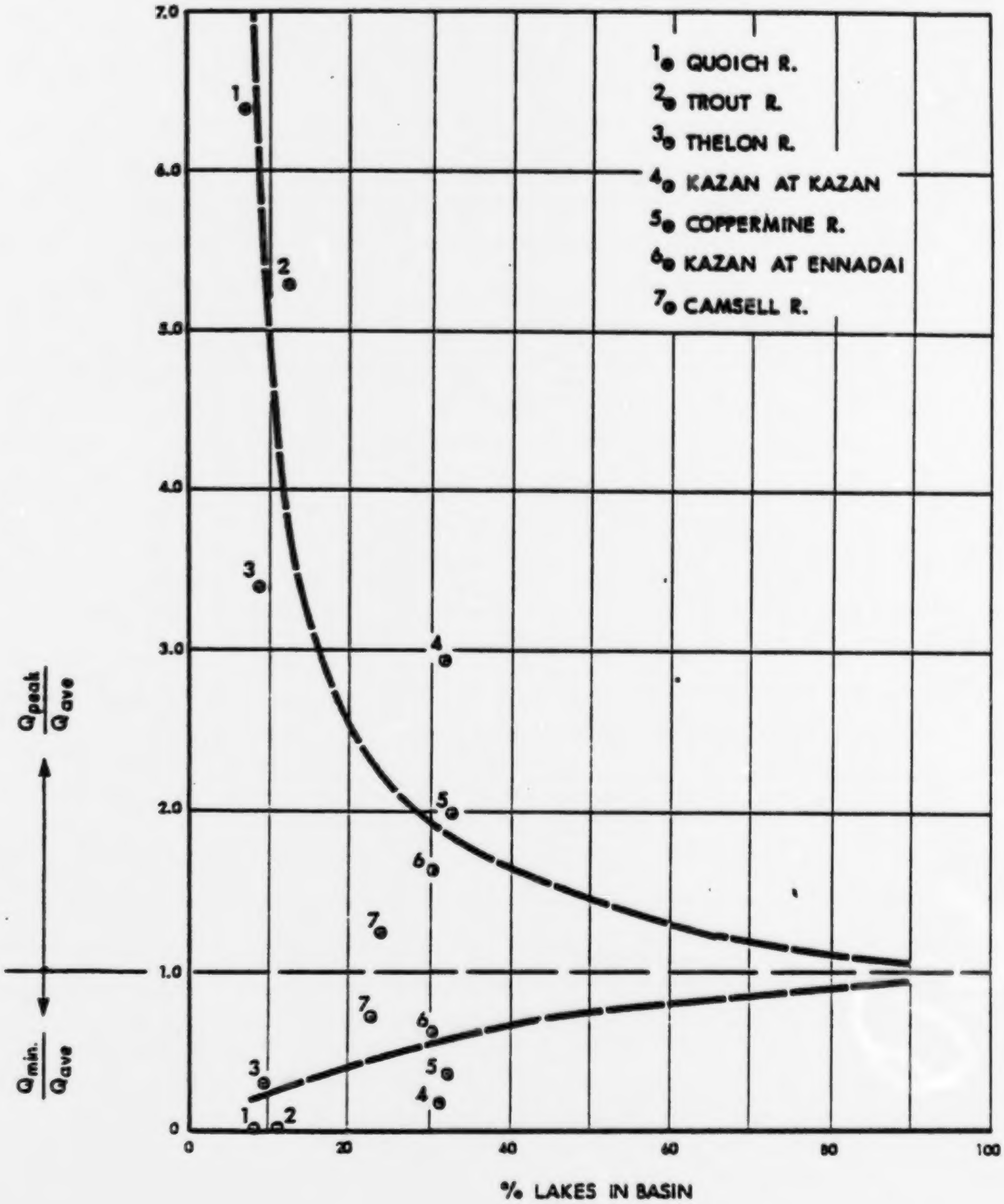
FIGURE A-5.6

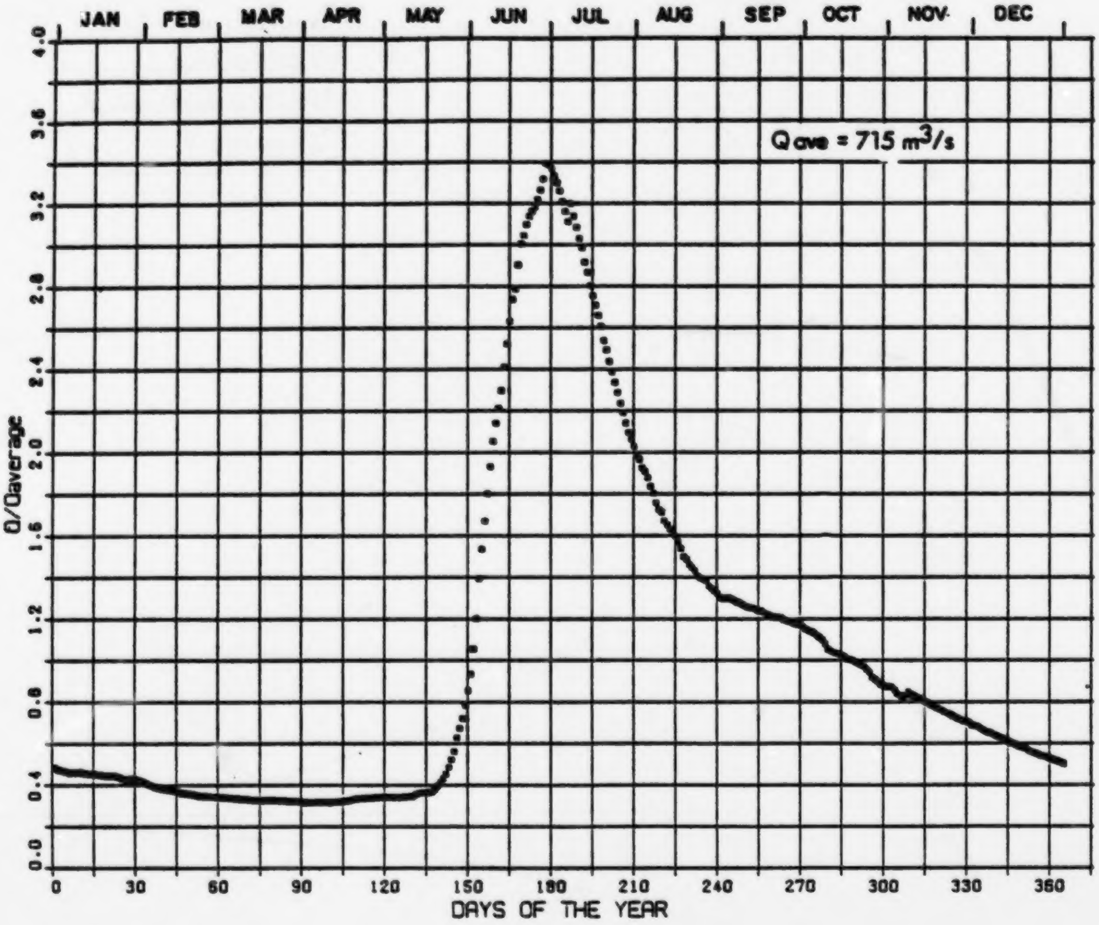


RELATIONSHIP BETWEEN
RUNOFF COEFFICIENT AND
LATITUDE OF CENTRE OF BASIN



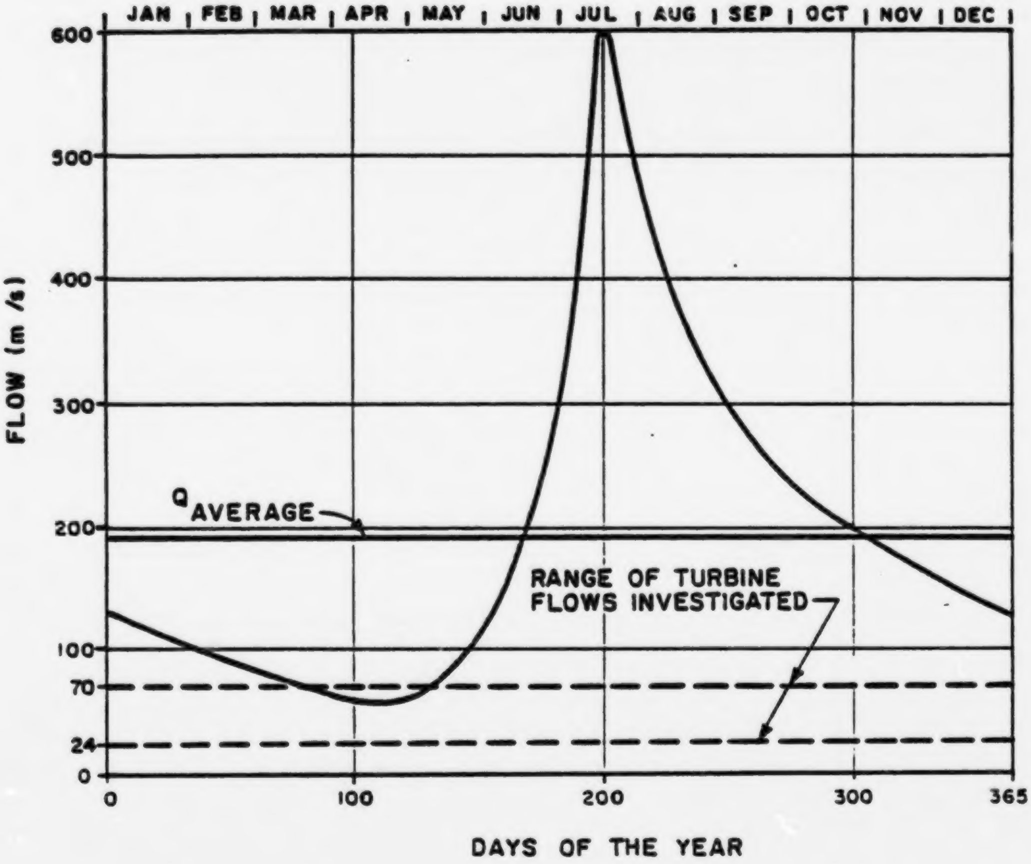
RELATIONSHIP BETWEEN
PROPORTION OF LAKES IN BASIN
AND MAXIMUM PEAK
AND MINIMUN FLOW RATIOS

FIGURE A-5.8



AVERAGE
DIMENSIONLESS DAILY FLOWS
THELON RIVER AT BAKER LAKE

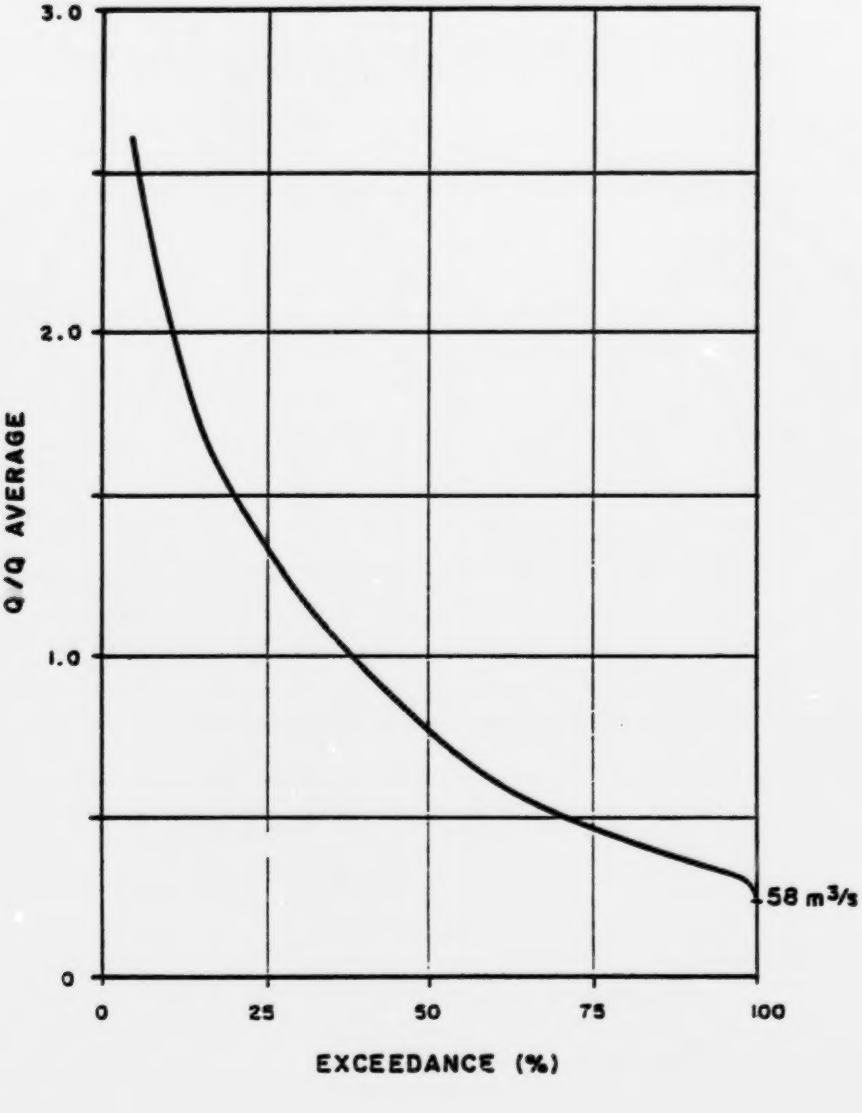
FIGURE A-5.9



$Q_{AVERAGE} = 191 \cdot 9\ m^3/s$

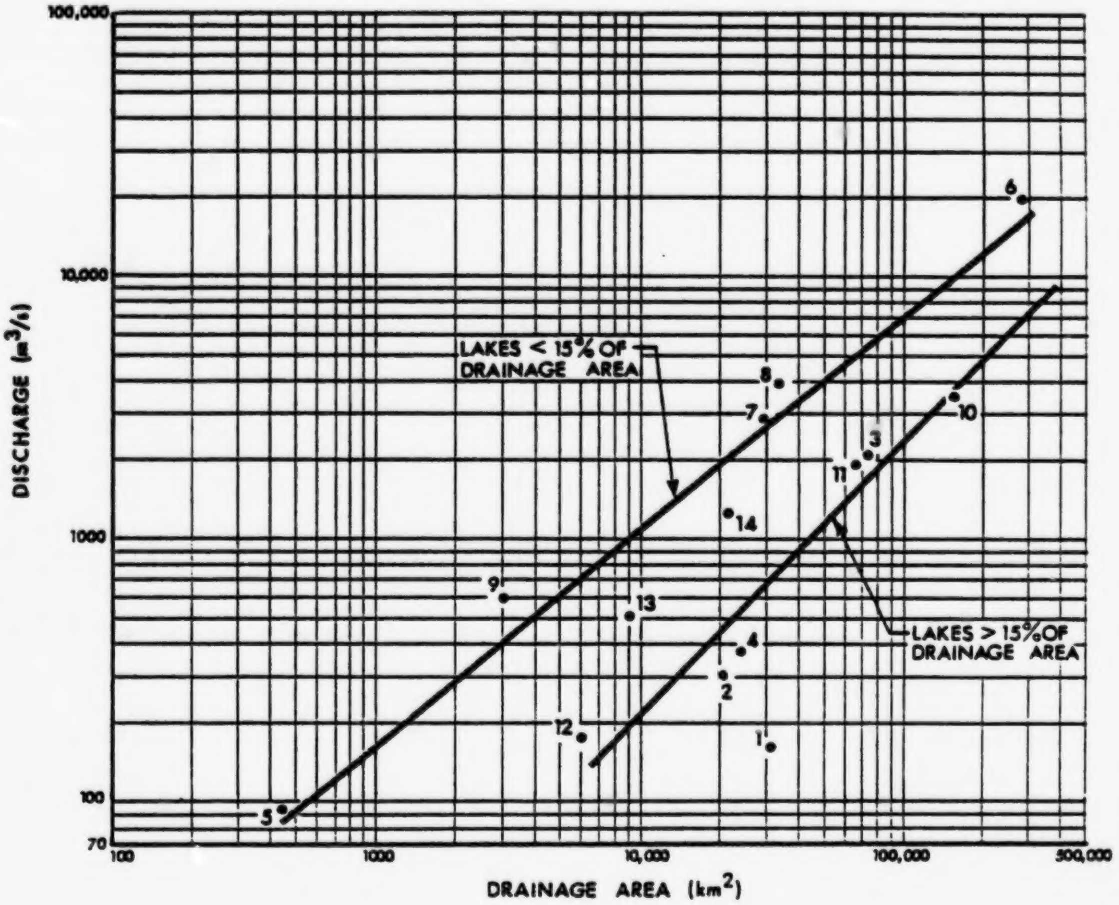
$Q_{MINIMUM} = 58 \cdot 0\ m^3/s$

COPPERMINE DEVELOPMENT
AVERAGE DAILY FLOWS
COPPERMINE RIVER
AT BLOODY FALLS



COPPERMINE DEVELOPMENT
DIMENSIONLESS DAILY FLOW
DURATION CURVE
COPPERMINE RIVER
AT BLOODY FALLS

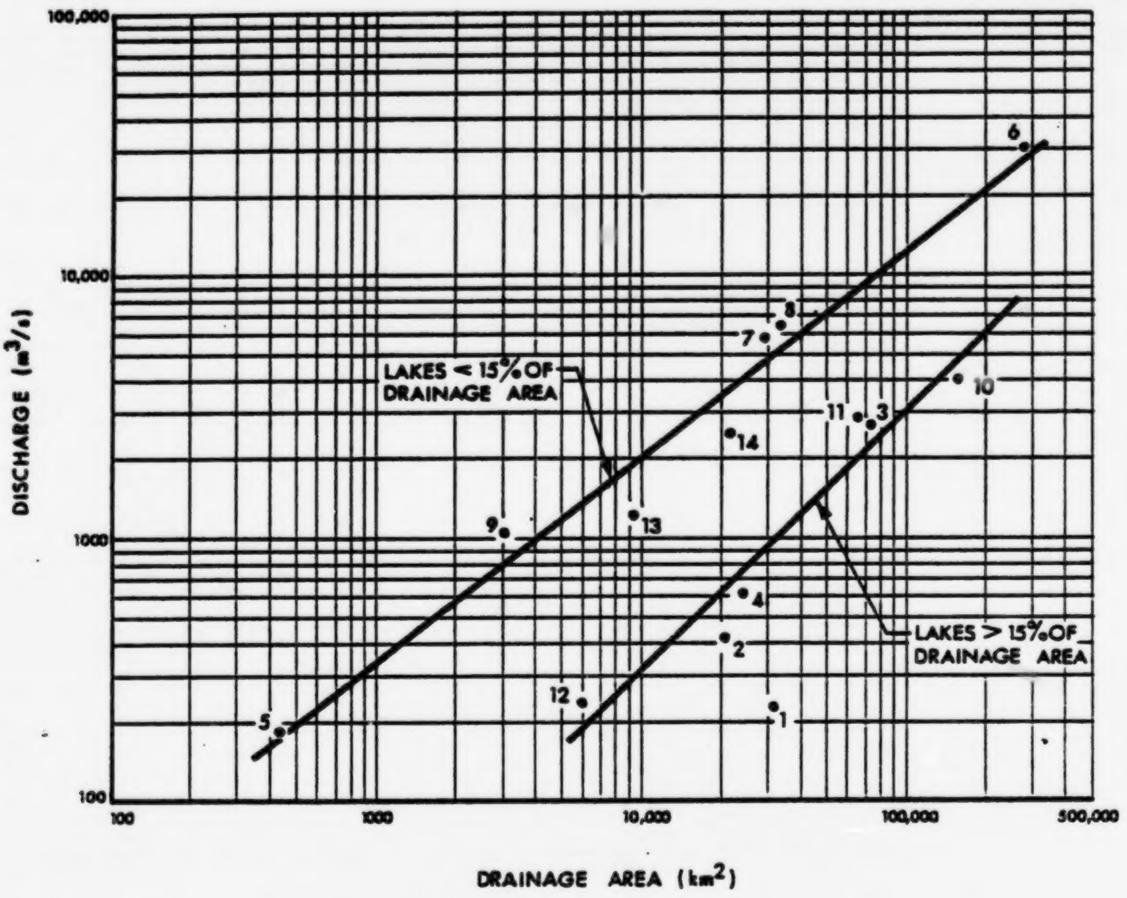
FIGURE A-5.11



1. CAMSELL R. AT OUTLET OF CLUT L. 10JA002
2. COPPERMINE R. AT OUTLET OF POINT L. 10PB001
3. KAZAN R. ABOVE KAZAN FALLS 06LC001
4. KAZAN R. AT OUTLET OF ENNADAI L. 06LA001
5. KITIYOUUO CK. NEAR BAKER LAKE 06MA002
6. LIARD RIVER NEAR THE MOUTH 10ED002
7. QUOICH R. ABOVE ST. CLAIR FALLS 06MB001
8. SOUTH NAHANNI R. ABOVE CLAUSEN CK. 10EC001
9. SYLVIA GRINNELL R. NEAR FROBISHER BAY 10TE001
10. THELON RIVER ABOVE BAKER LAKE 06MA003
11. THELON RIVER ABOVE BEVERLY LAKE 06JC002
12. TREE RIVER NEAR THE MOUTH 10GA001
13. TROUT RIVER AT FORT SIMPSON HWY. 10FA002
14. WILLOWLAKE RIVER NEAR THE MOUTH 10GB001

REGIONAL 1:20 YEAR FLOODS

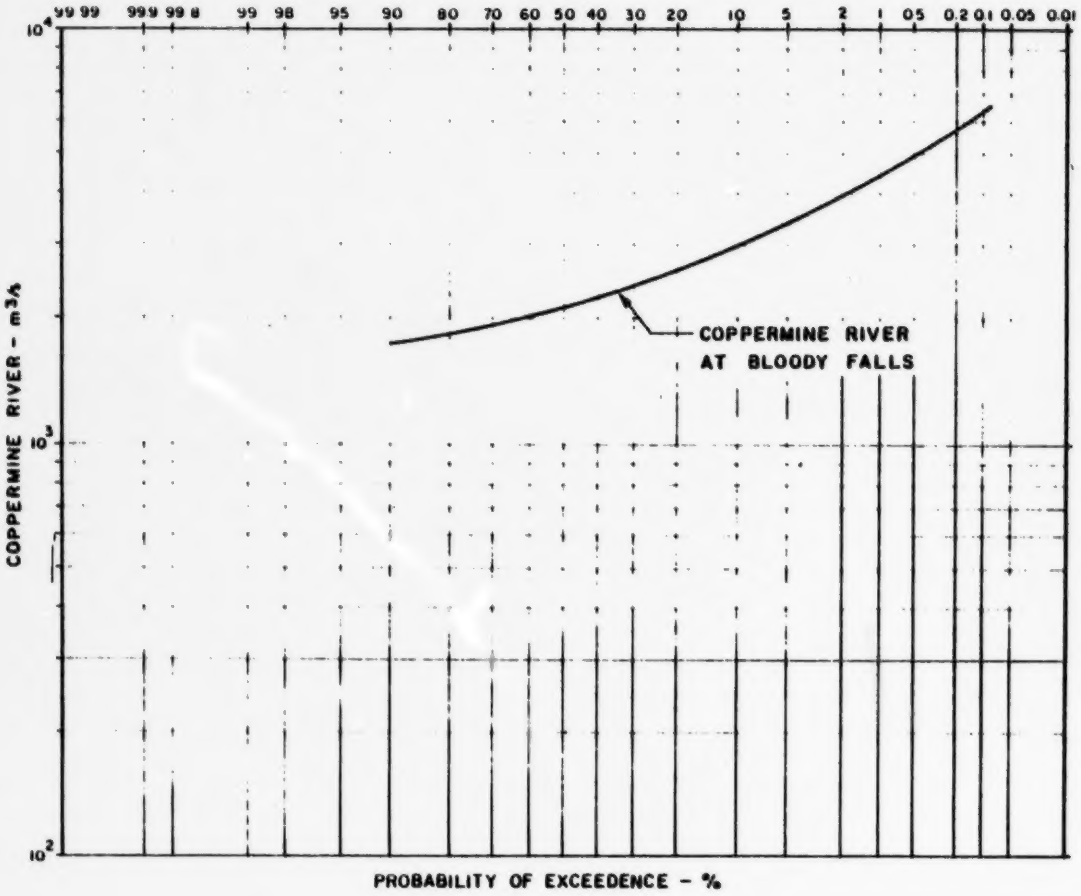
FIGURE A-5.12



1. CAMSELL R. AT OUTLET OF CLUT L.
10JA002
2. COPPERMINE R. AT OUTLET OF POINT L.
10PB001
3. KAZAN R. ABOVE KAZAN FALLS
06LC001
4. KAZAN R. AT OUTLET OF ENNADAI L.
06LA001
5. KITIYOUUQ CK. NEAR BAKER LAKE
06MA002
6. LIARD RIVER NEAR THE MOUTH
10ED002
7. QUOICH R. ABOVE ST. CLAIR FALLS
06MB001
8. SOUTH NAHANNI R. ABOVE CLAUSEN CK.
10EC001
9. SYLVIA GRINNELL R. NEAR FROBISHER BAY
10TE001
10. THELON RIVER ABOVE BAKER LAKE
06MA003
11. THELON RIVER ABOVE BEVERLY LAKE
06JC002
12. TREE RIVER NEAR THE MOUTH
10QA001
13. TROUT RIVER AT FORT SIMPSON HWY.
10FA002
14. WILLOWLAKE RIVER NEAR THE MOUTH
10GB001

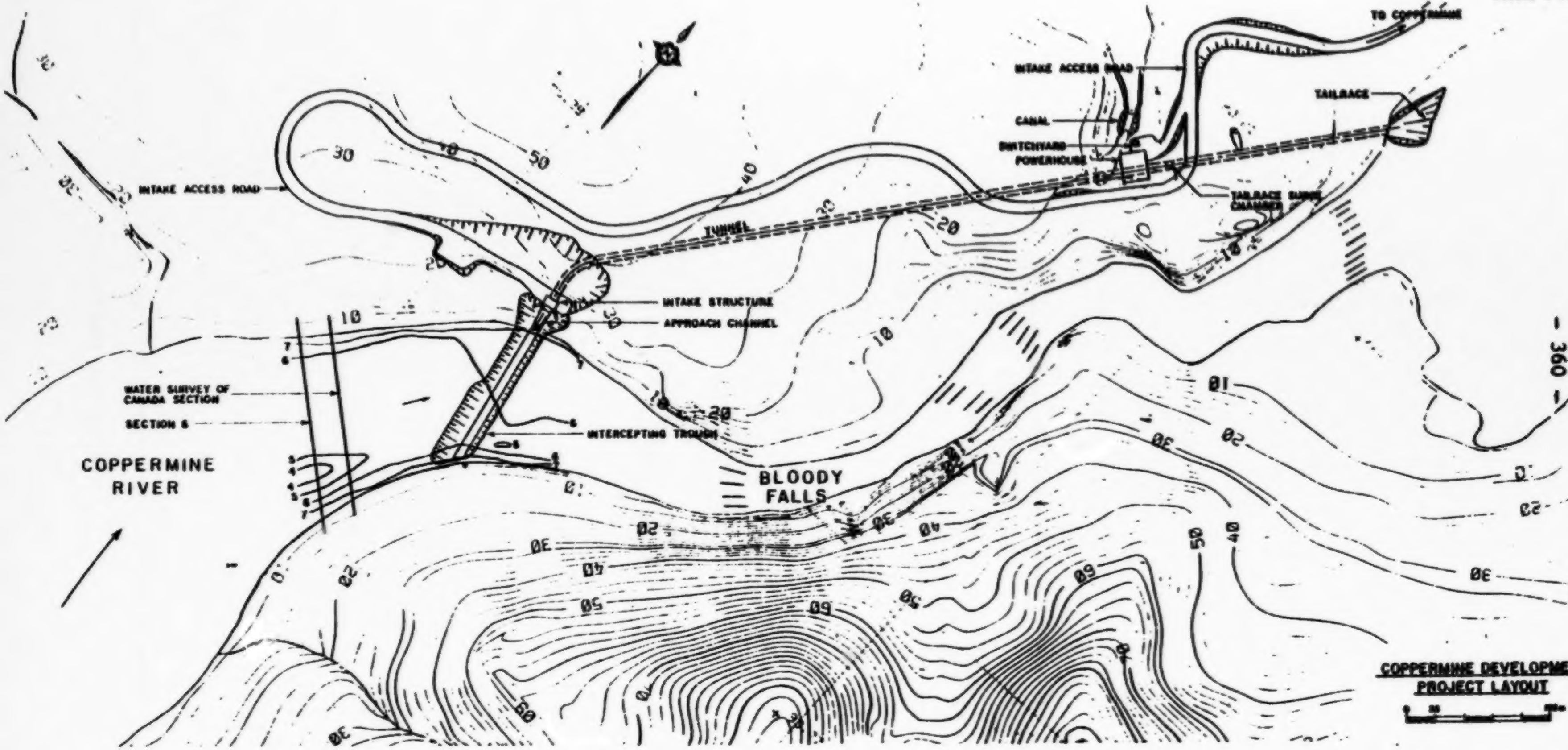
REGIONAL 1: 1000 YEAR FLOODS

FIGURE A-5.13



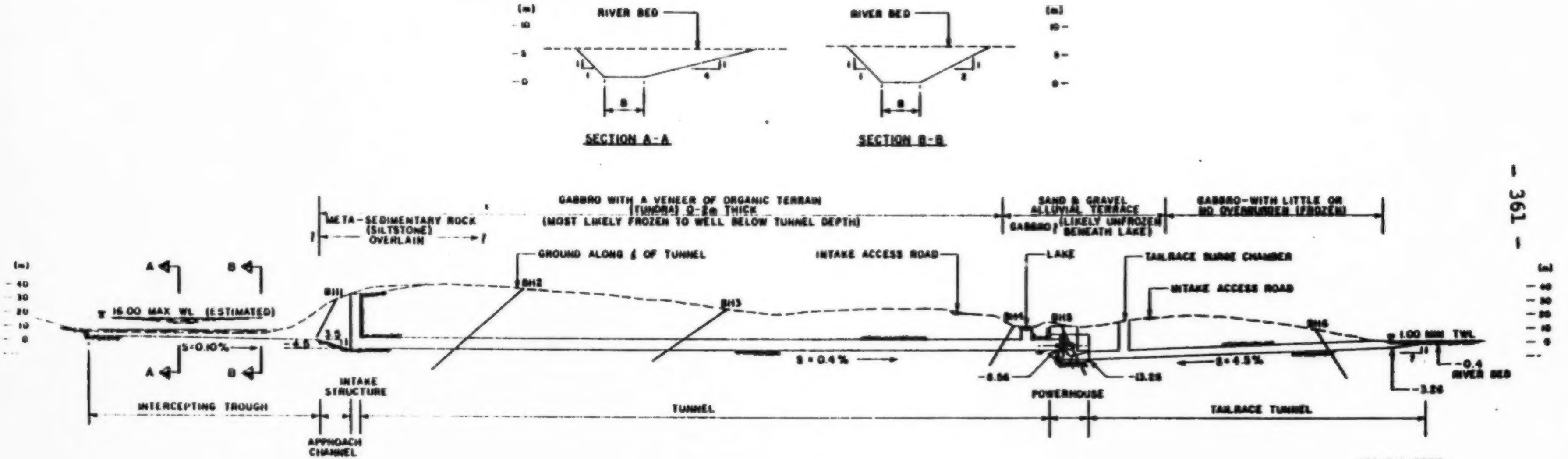
COPPERMINE DEVELOPMENT
DESIGN FLOODS

FIGURE A-3.1


TO COPPERMINE
INTAKE ACCESS ROAD
CANAL
SWITCHYARD
POWERHOUSE
TAILRACE
TAILRACE SURGE CHAMBER
TUNNEL
INTAKE STRUCTURE
APPROACH CHANNEL
INTERCEPTING TROUGH
WATER SURVEY OF CANADA SECTION
SECTION 6
COPPERMINE RIVER
BLOODY FALLS
10
20
30
40
50
60
70

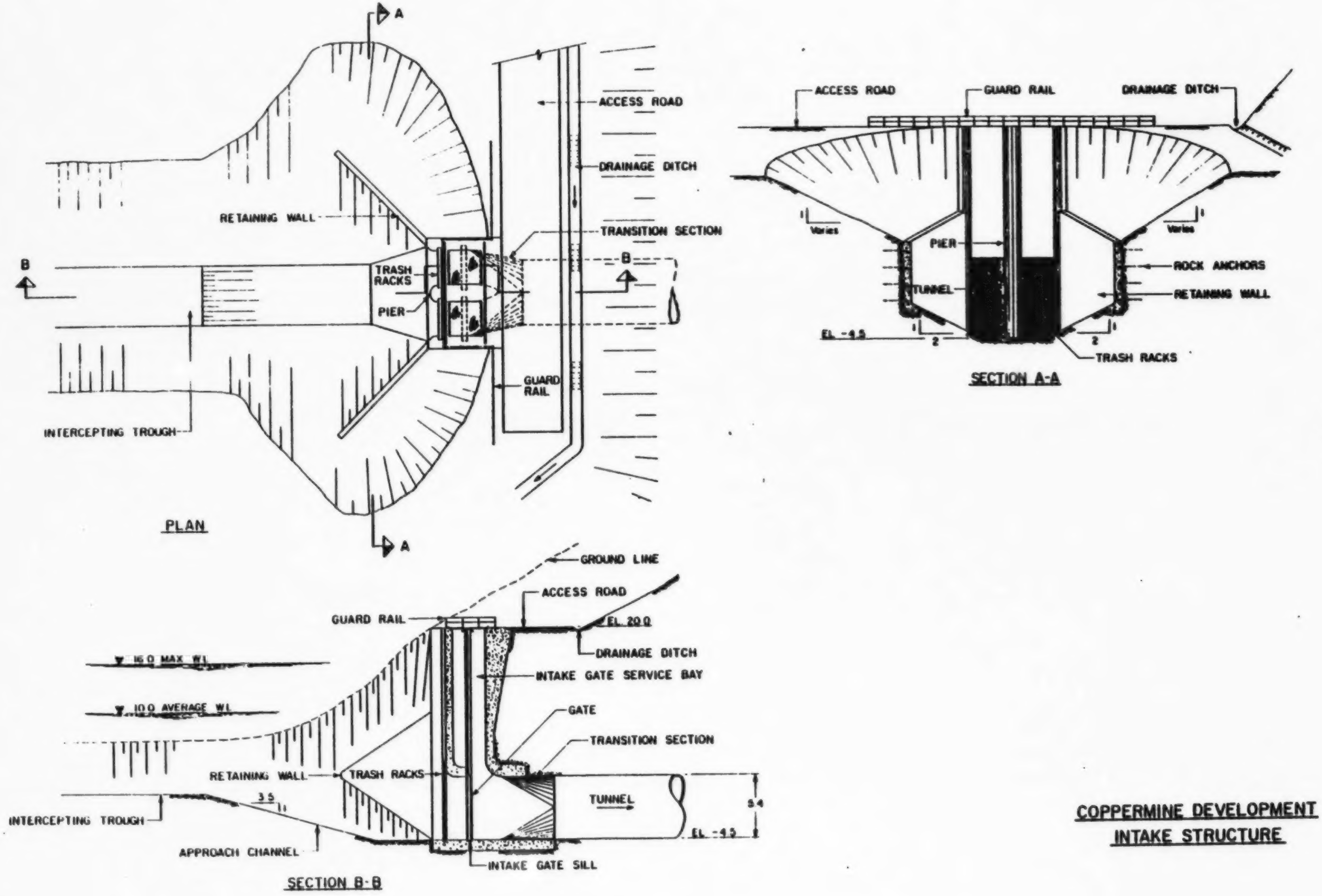
COPPERMINE DEVELOPMENT PROJECT LAYOUT

FIGURE A-7.2


(m)
10
5
0
RIVER BED
1
1
4
B
SECTION A-A
RIVER BED
(m)
10
5
0
1
1
2
B
SECTION B-B
META-SEDIMENTARY ROCK (SILTSTONE) OVERLAIN
?
?
GABBRO WITH A VENEER OF ORGANIC TERRAIN (TUNDRA) 0-2m THICK
(MOST LIKELY FROZEN TO WELL BELOW TUNNEL DEPTH)
SAND & GRAVEL ALLUVIAL TERRACE
GABBRO? (LIKELY UNFROZEN BENEATH LAKE)
GABBRO-WITH LITTLE OR NO OVERBURDEN (FROZEN)
GROUND ALONG ℄ OF TUNNEL
INTAKE ACCESS ROAD
LAKE
TAILRACE SURGE CHAMBER
INTAKE ACCESS ROAD
(m)
40
30
20
10
0
A
B
16.00 MAX WL (ESTIMATED)
S=0.10%
A
B
BH1
BH2
BH3
BH4
BH5
BH6
3.5
-4.5
S = 0.4%
-8.06
-13.26
S = 4.5%
1.00 MIN TWL
1
7
-0.4
RIVER BED
-3.26
(m)
40
30
20
10
0
INTERCEPTING TROUGH
APPROACH CHANNEL
INTAKE STRUCTURE
TUNNEL
POWERHOUSE
TAILRACE TUNNEL
SCALE 1:2000
NATURAL

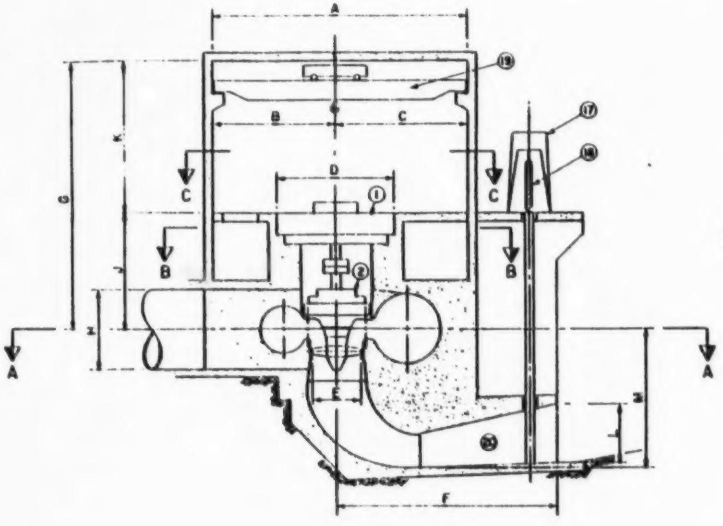
COPPERMINE DEVELOPMENT
DEVELOPED PROFILE ALONG INTAKE,
TUNNEL AND POWERHOUSE

FIGURE A-7.3

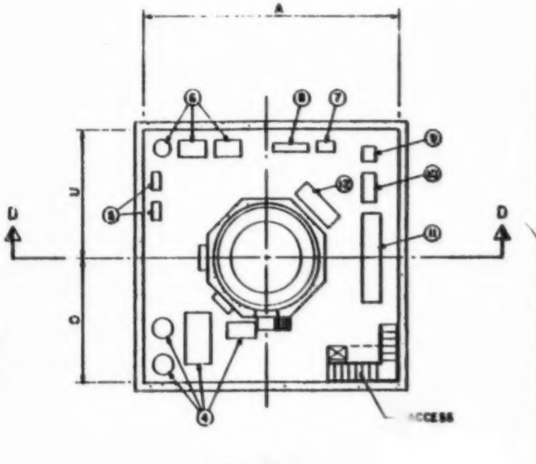

PLAN
A
A
B
B
RETAINING WALL
TRASH RACKS
PIER
INTERCEPTING TROUGH
ACCESS ROAD
DRAINAGE DITCH
TRANSITION SECTION
GUARD RAIL
SECTION A-A
ACCESS ROAD
GUARD RAIL
DRAINAGE DITCH
1
Varies
1
Varies
PIER
TUNNEL
ROCK ANCHORS
RETAINING WALL
EL -4.5
1
2
2
1
TRASH RACKS
SECTION B-B
GROUND LINE
ACCESS ROAD
GUARD RAIL
EL 20.0
DRAINAGE DITCH
16.0 MAX. W.L.
10.0 AVERAGE W.L.
INTAKE GATE SERVICE BAY
GATE
TRANSITION SECTION
RETAINING WALL
TRASH RACKS
TUNNEL
3.5
1
9.4
EL -4.5
INTERCEPTING TROUGH
APPROACH CHANNEL
INTAKE GATE SILL

COPPERMINE DEVELOPMENT
INTAKE STRUCTURE

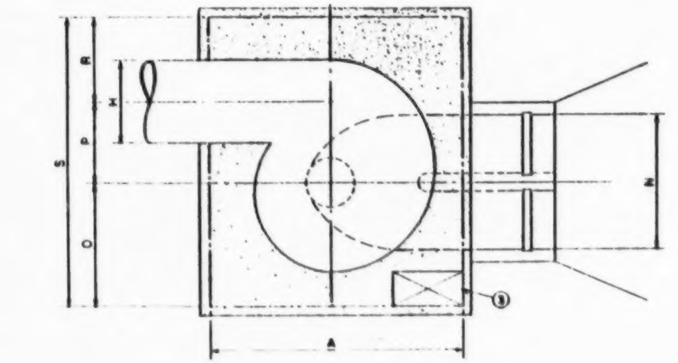
FIGURE A-7.4



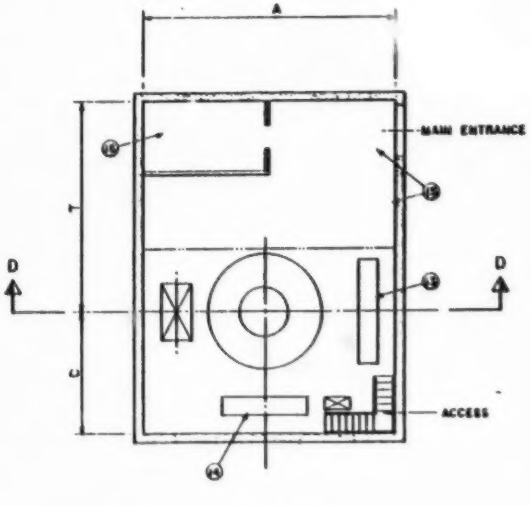
SECTION 'D-D'



SECTION 'B-B'



SECTION 'A-A'



SECTION 'C-C'

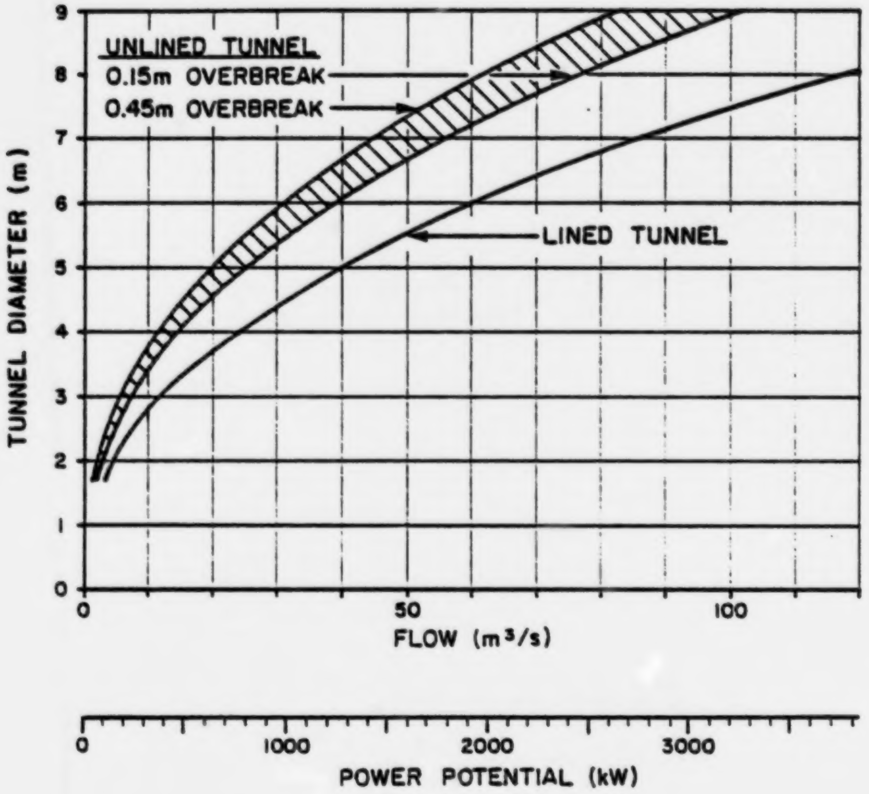
MAIN DIMENSIONS (m)	SCHEME No. 1	SCHEME No. 2	SCHEME No. 3	SCHEME No. 4
	Q=24m³/s	Q=46.4m³/s	Q=56m³/s	Q=70m³/s
A	13.00	15.25	16.40	17.80
B	6.50	6.75	7.40	7.80
C	6.50	8.50	9.00	10.00
D	6.10	7.50	7.80	8.60
E	2.41	3.38	3.62	4.10
F	10.80	15.10	15.80	17.60
G	14.50	16.75	17.50	18.50
H	3.85	5.40	5.79	6.60
J	7.00	7.50	7.50	7.50
K	7.50	9.25	10.00	11.00
L	2.85	4.00	4.30	4.85
M	6.70	9.40	10.10	11.35
N	6.50	9.10	9.80	11.10
O	6.00	7.30	7.60	9.00
P	3.98	5.58	5.97	6.80
R	4.40	5.20	5.40	5.80
S	14.38	18.08	18.97	21.60
T	11.00	14.20	15.50	16.50
U	8.40	10.80	12.00	13.00

LEGEND OF EQUIPMENT

① SYNCHRONOUS GENERATOR
② KAPLAN TURBINE
③ DEWATERING SUMP & PUMPS
④ GOVERNOR PUMP SET & AIR RECEIVERS
⑤ C.W. PUMPS & EQUIPMENT
⑥ H.P. COMPRESSORS & AIR RECEIVER
⑦ GENERATOR BRAKES CONTROL
⑧ CO_2 BATTERY SET
⑨ NEUTRAL EARTH. CUBICLE
⑩ POTENTIAL TRANSFORMER CUBICLE
⑪ UNIT DISTRIBUTION CUBICLES
⑫ GENERATOR BEARING COOLERS
⑬ ELECTRICAL SWITCH GEARS
⑭ AUTO. START/STOP CUBICLE
⑮ ERECTION AND UNLOADING BAYS
⑯ OFFICE/W. SHOP/STORE
⑰ CRANE
⑱ DRAFT TUBE GATE
⑲ POWER HOUSE CRANE
⑳ DRAFT TUBE

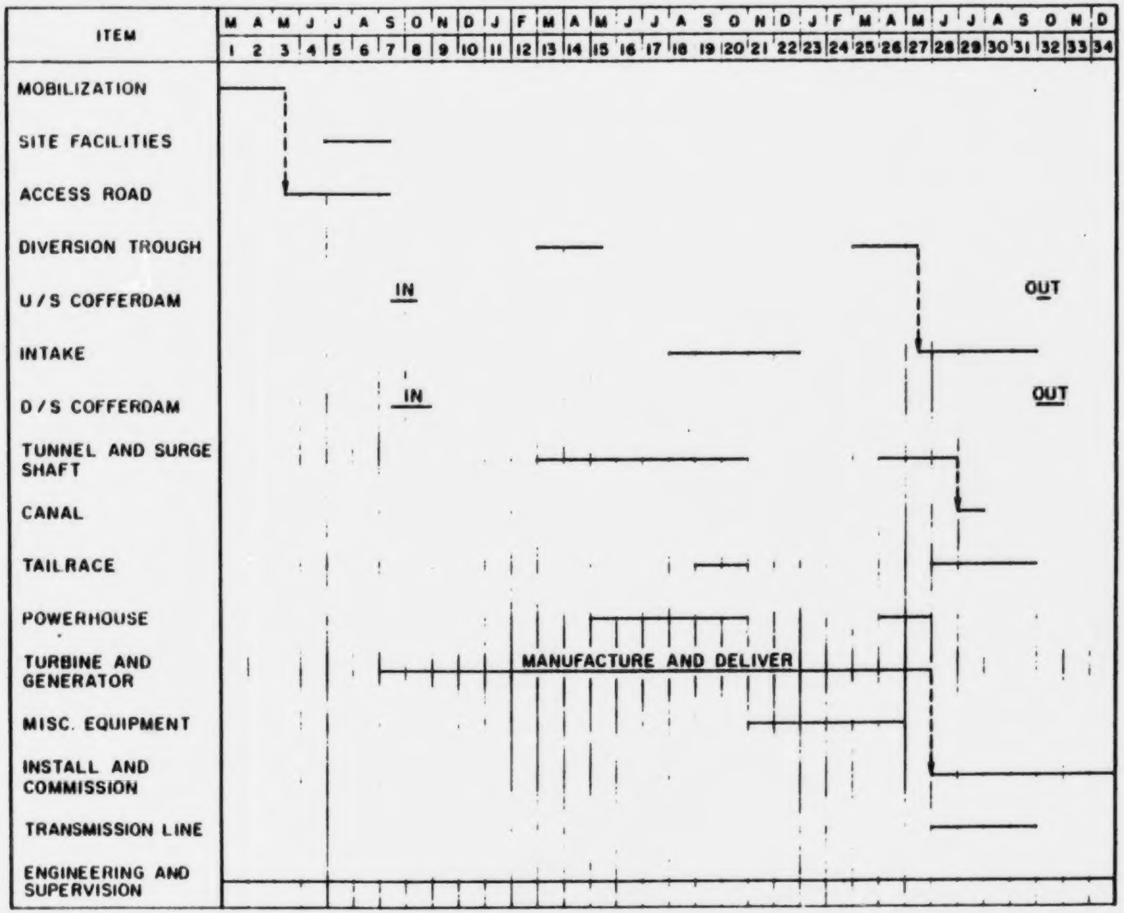
COPPERMINE DEVELOPMENT
DETAILS OF POWERHOUSE

FIGURE A-7.5



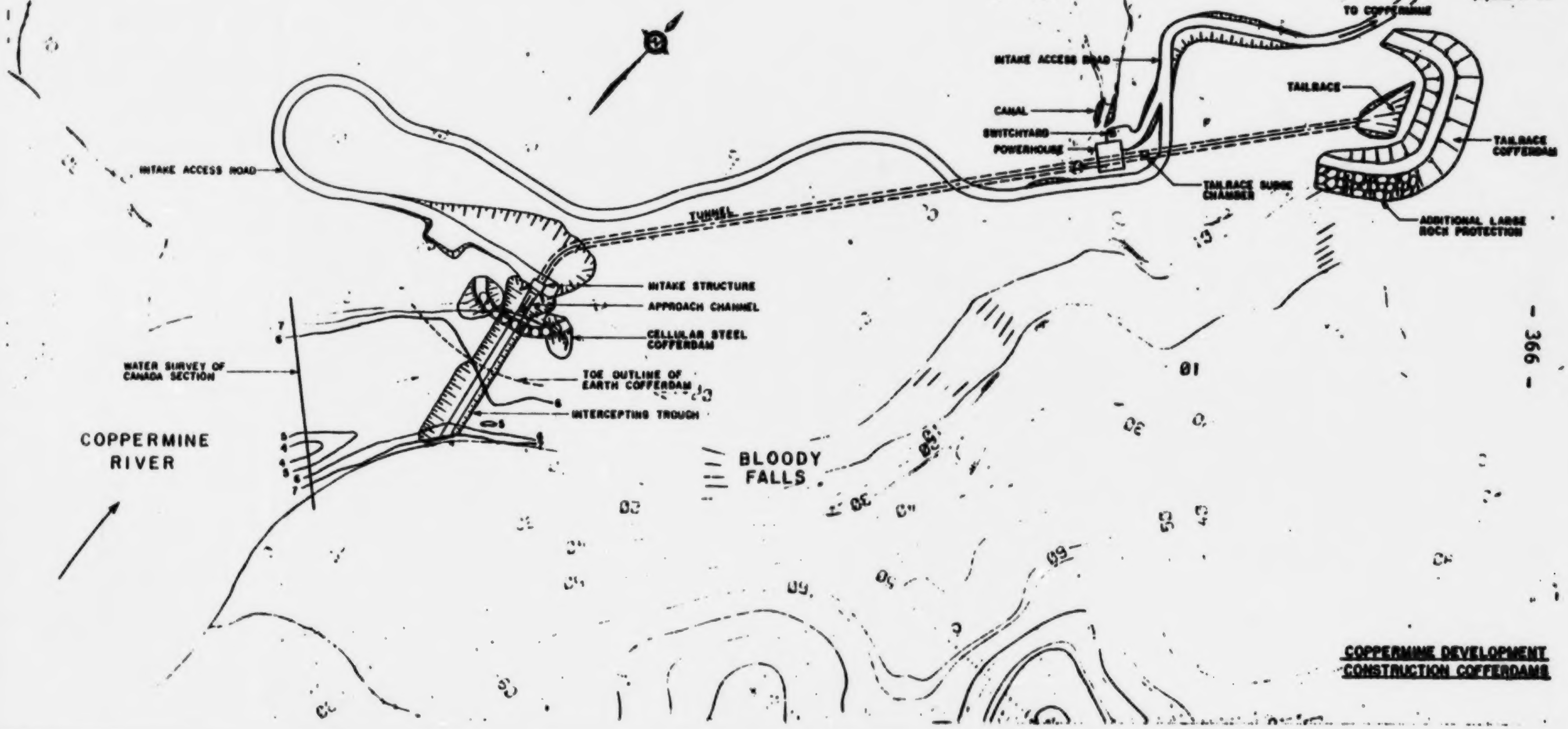
COPPERMINE DEVELOPMENT
TUNNEL DIAMETER vs
POWER AND FLOW

FIGURE A-7.6



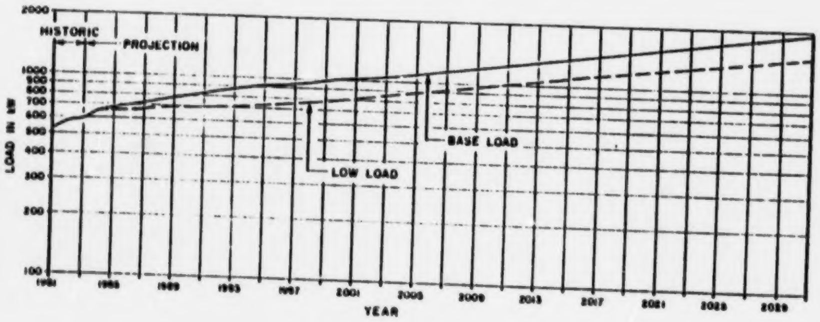
COPPERMINE DEVELOPMENT
CONSTRUCTION SCHEDULE

FIGURE A-7.7

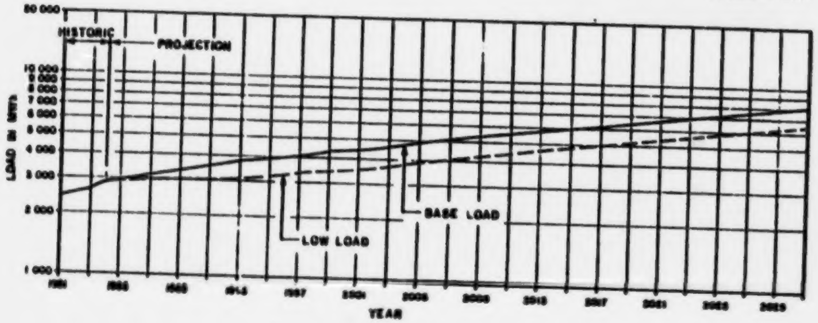

TO COPPERMINE
INTAKE ACCESS ROAD
CANAL
SWITCHYARD
POWERHOUSE
TAILRACE
TAILRACE COFFERDAM
TAILRACE SURGE CHAMBER
ADDITIONAL LARGE ROCK PROTECTION
INTAKE ACCESS ROAD
TUNNEL
INTAKE STRUCTURE
APPROACH CHANNEL
CELLULAR STEEL COFFERDAM
TOE OUTLINE OF EARTH COFFERDAM
INTERCEPTING TROUGH
WATER SURVEY OF CANADA SECTION
COPPERMINE RIVER
BLOODY FALLS
10
30
50
60

COPPERMINE DEVELOPMENT
CONSTRUCTION COFFERDAMS

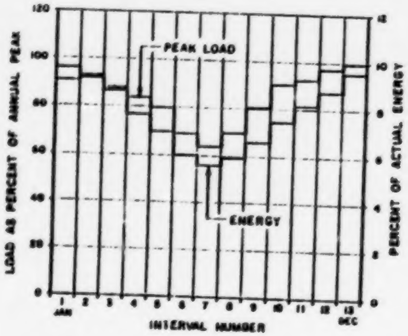
FIGURE A-8.1



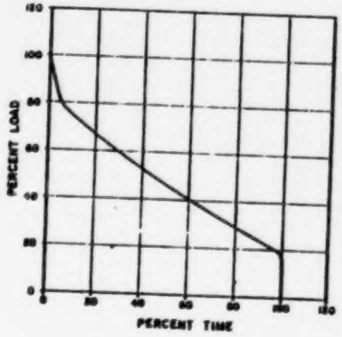
PEAK CURVE



ENERGY CONSUMPTION CURVE



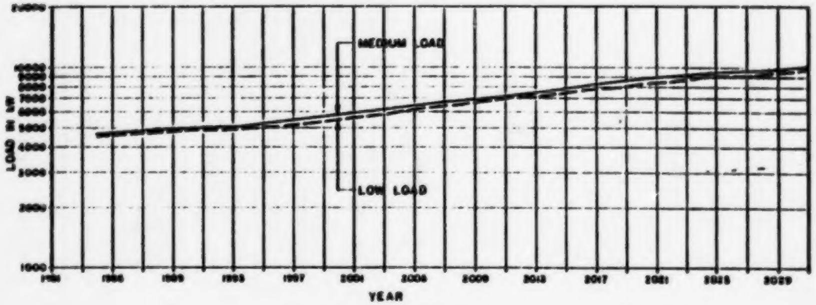
PEAK LOAD AND ENERGY VERSUS INTERVAL



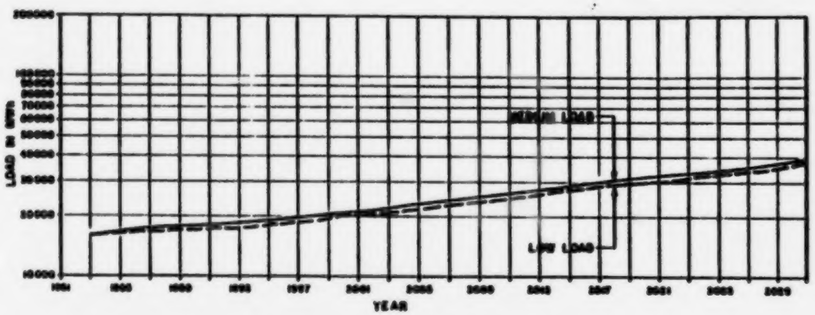
ANNUAL LOAD DURATION CURVE

COPPERMINE DEVELOPMENT
ELECTRICAL SYSTEM
LOAD CHARACTERISTICS

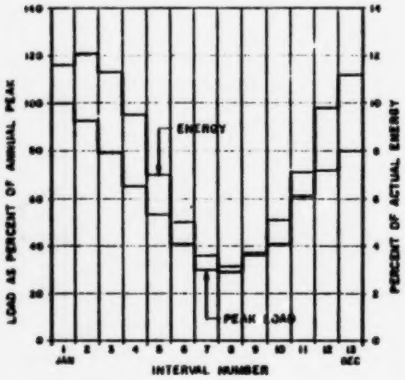
Figure A.-9.2



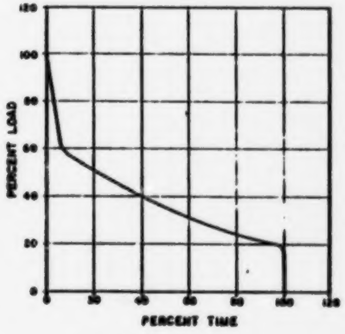
PEAK CURVE



ENERGY CONSUMPTION CURVE



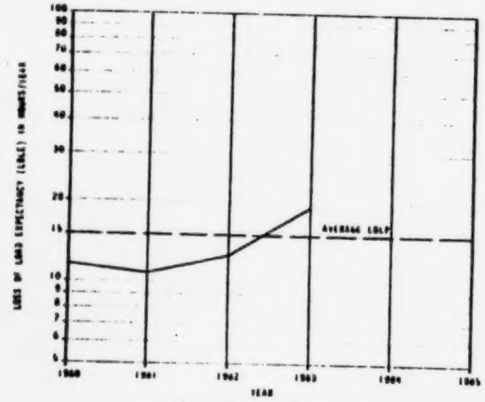
PEAK LOAD AND ENERGY VERSUS INTERVAL



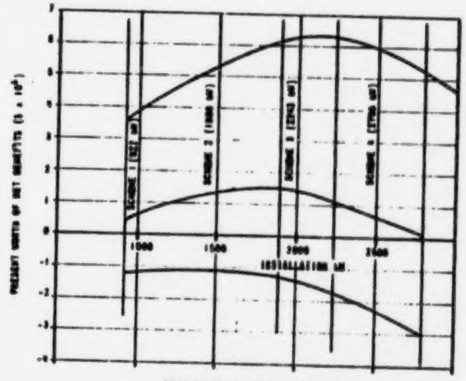
ANNUAL LOAD DURATION CURVE

COPPERMINE DEVELOPMENT
COMBINED (ELEC. + HEAT)
LOAD CHARACTERISTICS

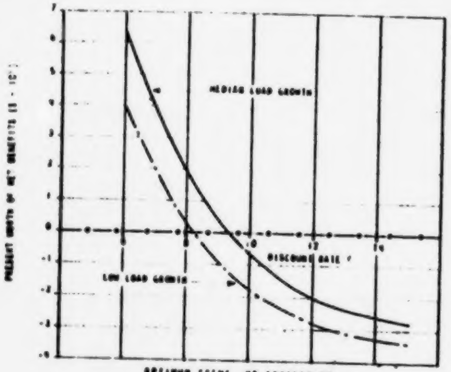
FIGURE A-8.3



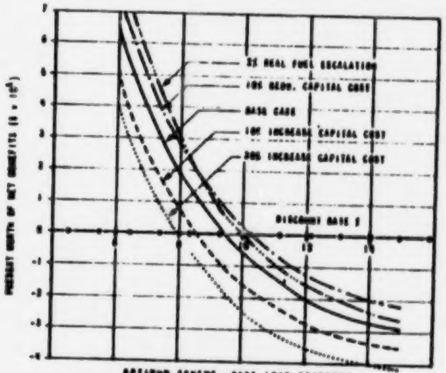
CHOICE OF RELIABILITY INDEX



SELECTION OF THE BEST SCHEMES
ALL HYDRO COMMISSIONED JAN. 1988



OPTIMUM SCHEME NO ESCALATION
COMMISSIONING YEAR = JAN. 1992



OPTIMUM SCHEME, BASE LOAD FORECAST
COMMISSIONING YEAR = JAN. 1992

NOTES

NET BENEFIT = SYSTEM CAPITAL AND OPERATING COSTS WITHOUT HYDRO LESS SYSTEM COSTS WITH HYDRO, PLUS HEATING CREDIT

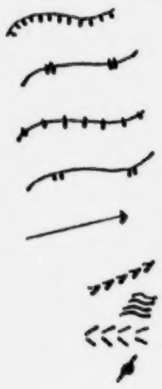
COPPERMINE DEVELOPMENT
PROJECT EVALUATION
INTERNAL RATES OF RETURN

LEGEND FOR COPPERMINE MAP

NCPC
LEGEND - SMALL HYDRO SITES

Origin	Map Symbol	Terrain Type	Soil or Rock Description	Landform Characteristics Thickness*	 Topography	Slope*	Surface Drainage and Groundwater	Comments
Glaciofluvial	Gb	Glaciofluvial Blanket	Sand and gravel	1-5 m	Flat to rolling	<3°-5°	Good	Source of granular material
Glaciofluvial	Gr	Glaciofluvial Ridge	Sand and gravel	>5 m	Ridged	9°-45°	Good	Source of granular material
Glaciofluvial	Gt	Glaciofluvial Terrace	Sand and gravel	>5 m	Flat	<3°	Fair to good	Source of granular material
Morainal	Mv	Moraine Veneer	Till--(a) silty clay till in Trout Lake; Trout River; (b) gravelly sand till at other sites	<1 m	Reflects underlying topography Reflects underlying topography	Up to 15° Up to 15°		
Morainal	Mb	Moraine Blanket	Till--(a) silty clay till in Trout Lake; Trout River; (b) gravelly sand till at other sites	1-5 m	Reflects underlying topography Reflects underlying topography	Up to 15° Up to 15°		
Morainal	Mp	Moraine Plain	Till--(a) silty clay till in Trout Lake; Trout River; (b) gravelly sand till at other sites	>5 m	Flat to undulating	3°-5°		
Morainal	Mm	Rolling Moraine	Till--(a) silty clay till in Trout Lake; Trout River; (b) gravelly sand till at other sites	>5 m	Undulating to rolling	5°-9°		
Morainal	Mr	Moraine Ridge	Till--(a) silty clay till in Trout Lake; Trout River; (b) gravelly sand till at other sites	>5 m	Ridge	9°-40°		
Rock	R	Bedrock -	(g) granite (b) basalt (gb) gabbro (ss) sandstone (d) dolomite (sh) shale					

Symbols



escarpment
depositional beach ridge - glacial lake origin
depositional beach - marine origin
erosional beach - marine origin
direction of flow in old meltwater channel
esker
ribbed moraine
crevasse fillings
drumlinoid moraine

Textural

g - gravel
s - sand
si - silt
c - clay
f - silt and clay
t - silty clay till
t - gravelly sandy till

Process

C - channeled
E - eroded, many closely spaced channels
TK - thermokarst
SF - solifluction

*Needs field checking for slopes, thicknesses

Examples

1) Percentage of Unit

tMp / gR
85% 0-15%

tMp - pR
50% 50%

2) Veneer of Unit Over Another Unit

tMv ←——(gravelly till) moraine veneer
gR ←——overlying granite

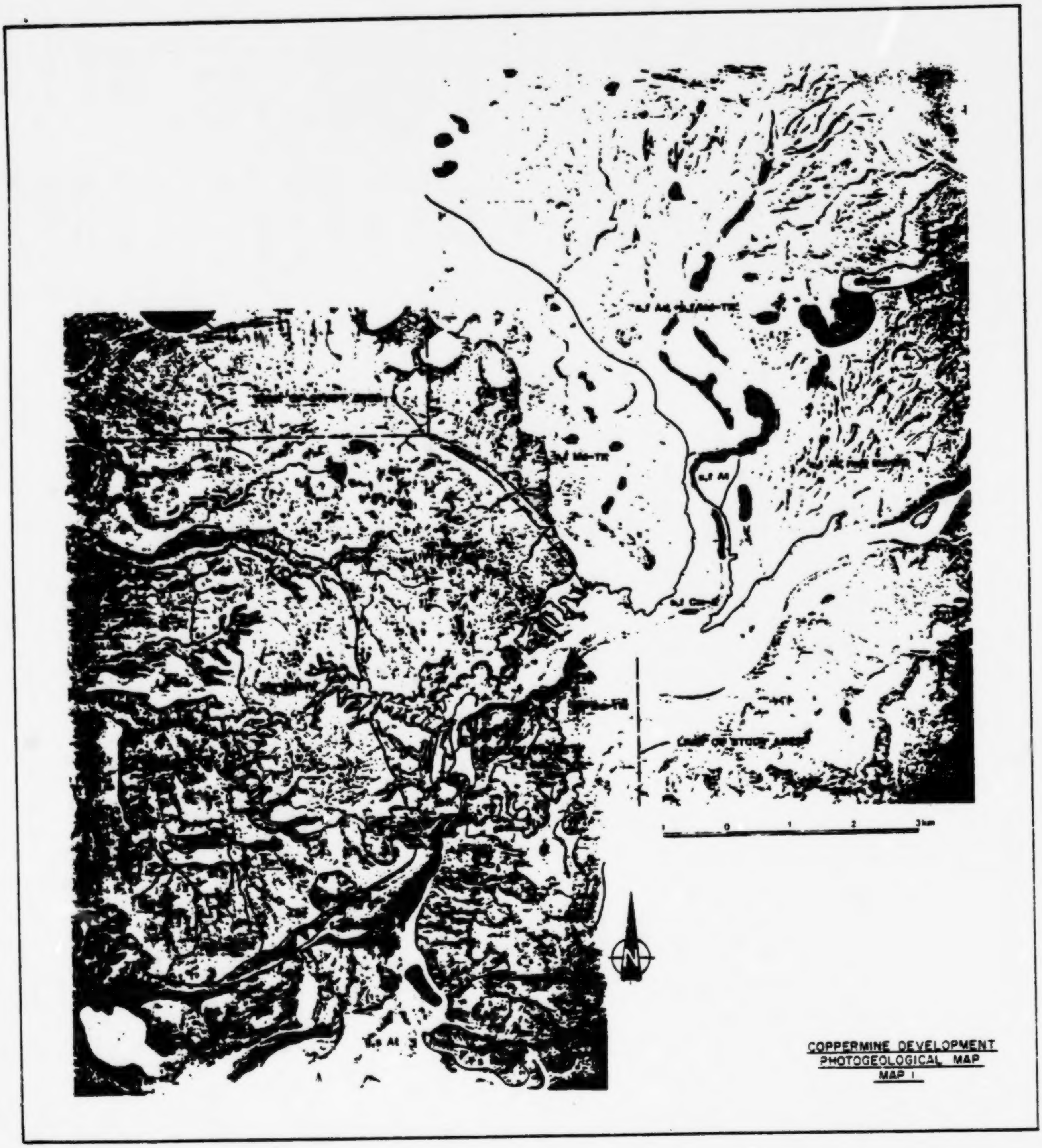
3) Processes Affecting Unit

s , f — sandy and fine grained
Mp ↑ marine plain
- TK ↑ thermokarst

LEGEND FOR COPPERMINE MAP

NCPC
LEGEND - SMALL HYDRO SITES

Origin	Map Symbol	Terrain Type	Soil or Rock Description	Landform Characteristics		Slope*	Surface Drainage and Groundwater	Comments
				Thickness*	Topography			
Organic	fOv	Fen Veneer	Fen	<1 m	Flat to depressional (may reflect underlying material)	<3°	Poor drainage, standing water	Wet ground surface
Organic	fOb	Fen Blanket	Fen	1-2 m	Flat to depressional (may reflect underlying material)	<3°	Poor drainage, standing water	Wet ground surface
Organic	fO	Fen (thick)	Fen	2-3 m	Flat to depressional (may reflect underlying material),	<3°	Poor drainage, standing water	Wet ground surface, may have shallow permafrost
Organic	pOv	Peat Veneer	Peat	<1 m	Flat to depressional	<3°	Poor drainage	Wet ground surface, shallow permafrost
Organic	pOb	Peat Blanket	Peat	1-2 m	Flat to depressional	<3°	Poor drainage	Wet ground surface, shallow permafrost
Organic	pO	Peat (thick)	Peat	2-3 m	Flat to depressional	<3°	Poor drainage	Wet ground surface, shallow permafrost
Organic	pOK	Peat (thick)	Peat	3 m	Rolling	<3°-5°	Poor drainage	Thick permafrost
Colluvial	Cv	Colluvial Veneer	Predominantly silt, clay, sand; some gravel & bedrock debris	<1 m	Gently to steeply sloping (reflects underlying unit)	3-40°	Good drainage	Probably underlain by shallow bedrock
Colluvial	Cb	Colluvial Blanket	Predominantly silt, clay, sand; some gravel & bedrock debris	1-5 m	Gently to steeply sloping (reflects underlying unit)	3-40°	Good drainage	Probably underlain by shallow bedrock; solifluction features.
Colluvial	Cm	Colluvial Mantle	Predominantly silt, clay, sand; some gravel & bedrock debris	>5 m	Gently to steeply sloping	3-40°	Good drainage	Unstable slopes may be present in this terrain unit; solifluction features
Alluvial	Av	Alluvial Veneer	Sand and silt; some gravel	<1 m	Reflects underlying topography	<3°	Good drainage	
Alluvial	Ap	Alluvial Plain	Sand and silt; some gravel	>5 m	Flat to gently undulating	<3°	Good drainage; high water table	Probably unfrozen
Alluvial	At	Alluvial Terrace	Sand and silt; some gravel	>5 m	Flat to gently undulating	<3°	Good drainage; high water table	
Alluvial	Ad_1	Alluvial Delta	Sand and silt; some gravel	>5 m	Flat to gently undulating	<3°	Good drainage	
Alluvial	Ad_2	Alluvial Delta (youngest)	Sand and silt; some gravel	>5 m	Flat to gently undulating	<3°		
Alluvial; Marine	Am	Alluvial; Marine Plain	Sand; some fines	>5 m	Flat to gently undulating	<3°	Fair to good	
Marine	Mn	Marine Nearshore	Sand	>5 m	Flat to ridged	3-15°	Good	
Marine	Md	Marine Plain	Sand, fines	3-5 m	Flat to rolling	3-5°	Fair to good	Permafrost in fine grained sediments
Glaciolacustrine	Lv	Glaciolacustrine Veneer	Sand, silt, clay	<1 m	Reflects underlying topography	<3°	Fair to poor; standing water in depressions	Organics and permafrost
Glaciolacustrine	Lp	Glaciolacustrine Plain	Sand, silt, clay	>5 m	Flat	<3°	Fair to poor; standing water in depressions	Organics and permafrost
Glaciolacustrine	Lpbc	Glaciolacustrine Beach Complex	Sand, some gravel	>5 m	Flat to ridged	>3° to 35°	Fair to good on ridges; poor between ridges	Permafrost in fine sediments between ridges


1 0 1 2 3km
N
COPPERMINE DEVELOPMENT
PHOTOGEOLOGICAL MAP
MAP 1

See pages 370-1 for map legend.